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BASELINE REPORT
PEÑAS BLANCAS HYDROELECTRIC PROJECT

INSTITUTO COSTARRICENSE DE ELECTRICIDAD

Prepared By:

September 2002

TABLE OF CONTENTS

Acronyms

ARESEP	Autoridad Reguladora de los Servicios Públicos (Public Services Regulatory Authority)
BNCR	Banco Nacional de Costa Rica (National Bank of Costa Rica)
CDM	Clean Development Mechanism
CER	Certified Emissions Reduction
CNFL	Compañía Nacional de Fuerza y Luz (National Power and Lighting Company)
ER	Emissions Reduction
ERF	Emissions Reduction Factor
GDP	Gross Domestic Product
GHG	Greenhouse Gase(s)
GW / GWh	Gigawatt / Gigawatt hour
ICE	Instituto Costarricense de Electricidad (Costa Rican Electricity Institute)
kW / kWh	Kilowatt / Kilowatt hour
LIBOR	London Inter Bank Offering Rate
LRMC	Long Run Marginal Cost
MINAE	Ministerio de Ambiente y Energía (Ministry of Environment and Energy)
MVP	Monitoring and Verfication Protocol
MW / MWh	Megawatt /Megawatt hour
NIS	National Interconnected System
O&M	Operation and Management
OCIC	Oficina Costarricense de Implementación Conjunta (Costa Rican Office on Joint Implementation)
SIEPAC	Sistema de Interconexion Electrica para America Central

1 PROJECT INFORMATION

1.1 Project Characteristics

Supplier's Name and Address:

Company Name:	Instituto Costarricense de Electricidad (ICE)
Address:	Edificio ICE, Sabana Norte
Zip code + City address:	Costado norte de La Sabana, San José
Postal Address:	P.O. Box 10032
Zip code + city postal address:	1000- P.O. Box 10032- San José
Country:	Costa Rica
Contact Person:	Ing. Carlos Obregón
Job Title:	Manager, ICELEC (ICE Electricity Division)
Tel number:	(506) 220-7484
Fax number:	(506) 220-6292
e-mail:	cobregon@icelec.ice.go.cr - www.ice.go.cr
Date of registration:	January 17, 2001

Local Contact's Name and Address:

Company Name:	Oficina Costarricense de Implementación Conjunta (OCIC)
Address:	Edificio CINDE, La Uruca
Zip code + City address:	1000, Segundo Piso Edificio CINDE, La Uruca, San José
Postal Address:	P.O. Box 7170
Zip code + city postal address:	1000, P.O. Box 7170, San José
Country:	Costa Rica
Contact Person:	Mr. Paulo Manso
Job Title:	General Manager
Tel number:	(506) 290-1283
Fax number:	(506) 290-1238
e-mail:	ocicgm@racsa.co.cr

Other Project Participants:

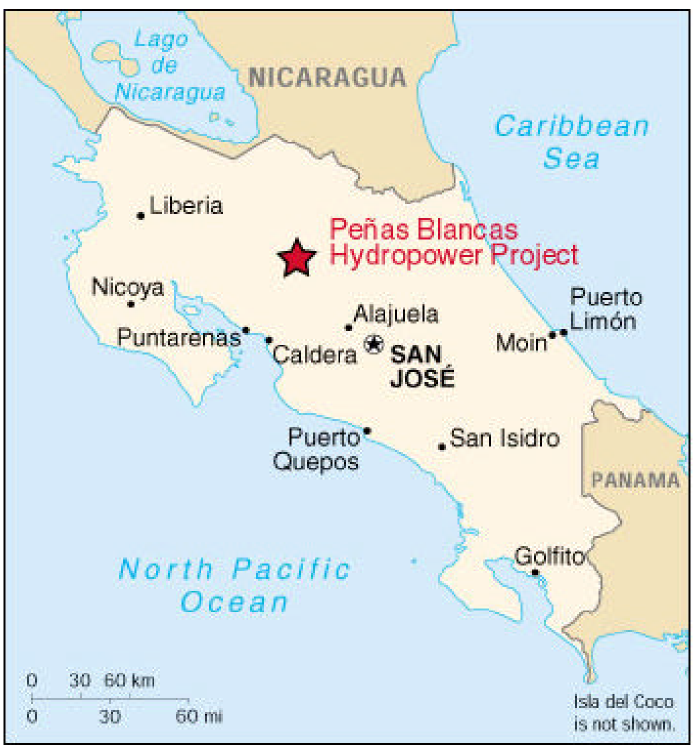
Company Name:	Banco Nacional de Costa Rica (BNCR)
Position in the project	Project Financier
Postal Address:	P.O. Box: 10015-1000, San José
Zip code + city address	Sección Fiduciaria del BNCR. Av.1 era, calles 2 y 4, San José 1000
Country:	Costa Rica
	Jorge Arturo Campos
Contact persons:	
Job Titles:	Head, Trustfund Department, BNCR
Tel number:	(506) 221-2223 / (506) 233-2524
Fax number:	(506) 223-6318
Date of registration:	January 13, 2000

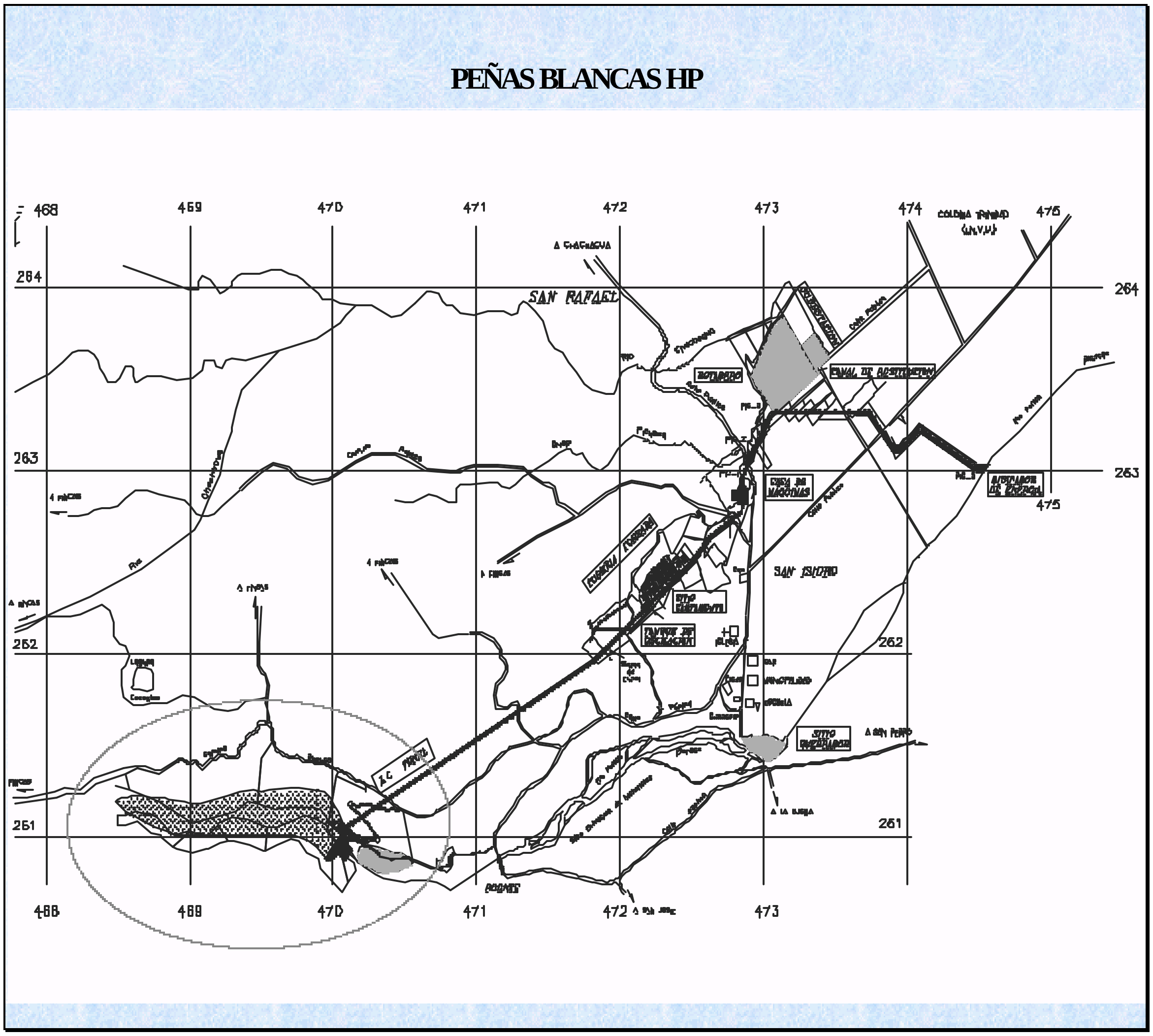
1.2 Project Abstract

Project Title	Peñas Blancas Hydroelectric Project
Project Location	Peñas Blancas River in Alajuela Province, Costa Rica Location as per Lambert coordinates is between 260.000 and 264.000 north and 468.000 and 475.000 east (see enclosed map).
Project Abstract	Peñas Blancas is a 35.4 MW hydroelectric project that will generate an average 164 GWh per year. It is being developed and constructed by the national utility, ICE, who will also operate the project. Financing for project construction is by means of bond emissions through a trust fund controlled by a state-owned bank (Banco Nacional de Costa Rica) – the trustor- and in which ICE is the trustee. ICE will lease the project from the trust fund for a period of 13-year. Energy will be delivered to the national grid and commercialized together with energy produced by ICE's other power plants.

Project starting date	June 1994
Construction starting date	March 2000 (under construction)
Construction finishing date	2002 (including commissioning)

Figure 1. Location of the Peñas Blancas Project





1.3 Background and Justification

1.3.1 Sector Background: The Energy Sector in Costa Rica

Costa Rica has no proven hydrocarbon resources. Indigenous energy resources are limited to hydropower, geothermal, wind and biomass. The most important of these resources is hydroelectric potential. Costa Rica's installed capacity in 2001 amounted to 1,645 MW, of which 1,228 MW was hydroelectric, 229 MW thermoelectric, 142 geothermal and 46 MW wind. Total generation in 2000 amounted to approximately 6,400 GWh, distributed by sector as follows: residential (44.6%), industrial (28.3%) and commercial (24.5%). The electricity consumption by the residential sector is mainly for cooking and lighting.

Electricity demand has grown steadily at a rate of 5-6% per year in the period 1990-2000, and electricity service coverage has reached 93% of the national territory. According to the National Expansion Plan (ICE, 2001), the projected annual growth in the demand for electricity will exceed 6.7% between 2001-2005, and 5.5% between 2005 and 2012. In order to satisfy this growth in demand, an increase of 1,031MW in capacity will be required.

Costa Rica has traditionally relied mostly on hydro resources for power generation. Although these will continue to play an important role in power development, Costa Rica current expansion plan includes some thermoelectric power generation, as well as other renewable-based production such as geothermal and wind power. The existing hydroelectric capacity in the country contains a large proportion of run-of-river plants that have little or no regulation to cover for hydrological variations.

1.3.1.1 Structure

The Instituto Costarricense de Electricidad (ICE), a state-owned, vertically integrated utility, manages the power sector. ICE owns also Compañía Nacional de Fuerza y Luz (CNFL), an independent distribution companies that operates in the largest market, the capital San Jose. CNFL also owns small generating plants. ICE is responsible for 82% of generation, 100% of high power transmission and 41% of distribution, and CNFL for 5% of power generation and 38% of distribution, mainly in the Greater Metropolitan Area.

ICE is a well-managed public utility, however, it has accumulated a very high level of debt. ICE's hydroelectric expansion plan during the last two decades has absorbed a large amount of the nation's resources. A significant percentage of the entire public external debt and the nation's debt service payments have gone to the energy sector. Financing the cost the expansion program is ICE's most important challenge to accomplishing its objective. Furthermore, although public sector energy objective favor the use of renewable sources, the economic-reality and investment-capability of the sector dictates that it will favor thermal plants with a lower capital investment cost. Therefore, for renewable generation projects to move forward carbon offset trade or other incentives will be needed.

Power is also generated by the private sector (14%). Under current legislation that permits limited participation of the private sector in power generation, independent generators and self-generators have entered the market since 1990 under limited conditions -- mostly to sell power to ICE and to distributors. In addition, municipal entities and rural electrification cooperatives also generate (8.5%) and distribute (21%) electricity.

The Ministry of Natural Resources, Environment and Energy (MINAE) performs policy functions. MINAE is also responsible for the supervision of ICE and is the governmental agency responsible for granting natural resources concessions (e.g. water and generation concession).

The Public Services Regulatory Authority (ARESEP), a multi-sector agency, is in charge of regulating the power and other sectors (telecommunications, hydrocarbon, irrigation, public transportation, maritime and air services, rail cargo transportation and waste disposal). ARESEP has a high degree of autonomy for regulating public services. It is responsible for setting prices and tariffs for public services and exerts regulatory oversight over its operations.

1.3.1.2 Regulatory Framework

Law No. 7329 (1993), the Law for Concessions of Public Services, sets the legal framework in Costa Rica. The current regulatory framework does not follow reform trends that have taken place in most of the countries of Latin and Central America. A bill sent to Congress by the Government in early 2000, that would unbundled ICE's activities and would create a bulk supply market, failed to be approved and was withdrawn by the Government in view of opposition. Currently any initiatives to reform the sector are on hold.

In Law No. 7329, the sector is regulated by laws 7200 and 7508 which support limited development of privately owned power using renewable energy resources:

(a) Law No. 7200 (1990) promotes small-scale exploitation of hydraulic potential and other renewable sources and allows private independent generators and self-generators using renewable energy resources to sell energy to the public electricity system via ICE. The law limited the size of the units to less than 20 MW and limited to 15% the aggregated installed capacity owned by independent generators. The law also required local ownership of at least 65% of the share capital in each project.

(b) Decree No. 7508 (1995) modifies Law No. 7200 by raising the limits for independent generators' participation to 30% of the total installed capacity in the system. It also raised the maximum size of the units to 50 MW and reduced the required percentage of local capital participation to 35%. It also required that the concessions for new (alternative and renewable energy) capacity would be awarded under competitive bidding procedures according to bid price and technical, economic, and financial evaluation of the bidder's proposed project. The decree authorized ICE to enter into international agreements for electricity transactions with other regional or state-owned utilities

After opening the sector to private participation in 1990 under Law No. 7200 (subsequently modified in 1995 by Law No. 7508), a number of private generators with an aggregate capacity of 210 MW secured contracts to provide power to ICE. Participation of private generators in the total production of ICE has steadily grown and now represents 14% of the total generation.

In accordance with current regulations ICE must present tariff schedules for ARESEP's approval.. ARESEP has developed tariff scheme that intend to remunerate energy and capacity charges in a way that better represents the value added to the system by these different products. Supply contracts based on such principles contain prices for peak and off-peak energy.

1.3.2 Project Background

ICE initiated studies for the development of energy resources in the Peñas Blancas River in 1972, with the intention of using the river as an additional source of water for the Arenal reservoir, the largest in the country. In 1987 and 1989 the focus of the studies shifted to exploring the possibility of developing a hydropower project on the Peñas Blancas River itself. Six project location and design options were considered, and one was finally selected on the basis of financial and environmental considerations.

The Peñas Blancas project is a run-of-the-river hydropower plant that will have a 49 meter high dam, a daily storage reservoir with a capacity of 2.0 hm3 and one power house with two vertical Francis type turbine generator units that add up to 35.4 MW of capacity. A 2 km-long tunnel will form the project's penstock, providing a gross head of 130.5 meters. The project is expected to generate 164 GWh/year on average, contributing to an annual reduction in greenhouse gas emissions of 87,826 tons of CO_2 equivalent on average during the 10-year crediting period.

Given the reduction of international soft credits for public sector infrastructure projects ICE had to seek alternative and innovative financing options. In virtue of that, a trust fund was created with the National Bank of Costa Rica (BNCR) as Trustor, and ICE as Trustee. The trust fund's specific purpose is to emit bonds to finance the Peñas Blancas hydroelectric project. Once construction is completed, ICE will lease the project from the trust fund and will operate it for 13 years to cover the acquired financial obligations from the bond emissions. At the end of the 13-year period, in 2015, ICE has a purchase option with the trust fund through which it plans to acquire the project.

1.3.3 Project Partners

The project partners are ICE, BNCR, and the bondholders of the trust fund[1]. ICE's core business is the energy sector, where it is the major energy producer and distributor as well as the only energy transmitter in Costa Rica. ICE is also in the telecommunications sector, where it has a monopoly and is therefore the only provider of telephone and Internet services in the country. ICE conceptualized, elaborated the pre and feasibility studies, is constructing and will operate the Peñas Blancas hydroelectric project. It also plans to purchase the project in 2015.

BNCR, a state-owned bank, is the largest bank in Costa Rica. The Bank was created in 1914 and it currently has over 4,000 employees and 140 branch offices throughout the country. Its core business is the financial sector, where it is one the most important financial intermediaries in the country, serving a wide range of customers. BNCR has a portfolio of trust funds worth over $200 million. BNCR is the administrator of the trust fund for the Peñas Blancas project.

The bondholders of the trust fund are private investors who chose to invest in the project. Throughout the period 2002-2015, bondholders will receive a return on their investment.

1.3.4 Investment design

The construction of the Peñas Blancas Hydroelectric project will be financed by means of bond emissions through a trust fund to be controlled by the BNCR as the trustor and with ICE as the trustee. The trust fund for Peñas Blancas was established on January 13, 2000. In addition to the trust fund contract, there are three other contracts. One contract for the emission of bonds whereby a broker was hired to sell the bonds. Another, between ICE and the trust fund through which the trust fund contracts ICE for the design and construction of the project. Finally, ICE leases the project through the trust fund under a contract. The lease will allow ICE to cover the financial obligations of the bonds emissions. The lease includes ICE's purchase option for the project at the end of the 13-year period. All contracts have been signed.

ICE's financial commitments consist in paying a lease for the project during the 13-year period of 2002-2015. In addition, ICE gave the trust fund a $19 million guarantee in case it not purchases the project in 2015. The trust fund, through the investment of bondholders, raised the $70 million (see Table 1) required to develop the project. BNCR is committed to properly manage the trust fund throughout its lifetime. A $70 million emission of various types of bonds has already been completed. One thousand-dollar bond was issued for periods between three to fourteen and a half years, and was independently rated as AAA due to the high security on capital return.

Table 1 – Project costs

Distribution of Expenses for Project Development	**Amount (million US$)**
Civil Works	31.8
Equipment	22.5
Emission and Trust Fund Expenses	0.7
Indirect Trust Fund Expenses	1.7
Sub-Total	*56.7*
Estimated Financial Expenses	13.3
Total Project Cost	*70.0*

[1] The formal name of the trust fund is "Fideicomiso de Titularización y Desarrollo de Infraestructura Eléctrica Proyecto Hidroeléctrico Peñas Blancas"

The yield of bonds is variable, with reference base to the LIBOR set at a minimum of 6.5%, with the exception of two emissions. A detail of the various bonds emitted and yields is given in the table 2 below:

Table 2 - Bonds information

Code	Emission Date	Expiration Date	Gross Rate of Return	Total Value of Emission (US$)
PHPB03	25-08-2000	25-08-2003	n.a.	4.500.000
PHPB04	25-08-2000	25-08-2004	n.a.	3.500.000
PHPB06	31-01-2001	31-01-2006	Libor+3.500%	4.500.000
PHPB07	25-08-2000	25-08-2007	Libor+3.500%	5.000.000
PHPB08	31-07-2000	31-07-2008	Libor+4.000%	3.500.000
PHPB10	25-08-2000	25-08-2010	Libor+4.000%	5.500.000
PHPB11	31-01-2001	31-01-2011	Libor+4.000%	4.000.000
PHPB12	31-01-2001	31-01-2012	Libor+4.000%	4.000.000
PHPB13	26-08-2000	26-08-2013	Libor+5.000%	7.500.000
PHPB15-A	30-07-2001	30-07-2015	Libor+5.000%	9.000.000
PHPB15-B	31-01-2001	31-01-2015	Libor+5.000%	19.000.000
			TOTAL	***70.000.000***

1.3.5 Current Status

Project construction is now underway by ICE. The construction is proceeding as scheduled and considerably faster than the average project execution time for ICE, in part because the financing scheme has also permitted an agile system for supplies and inputs purchasing. There have been 11 bond issues for a total of $70 million, the total investment need.

All studies, project design, legal requirements and authorizations were satisfied and approvals obtained before construction started, including an Environmental Impact Assessment Study. As required by the MINAE, the project has established a permanent system of community contact, and maintains excellent relations.

1.4 Intervention

1.4.1 Project Goals

From the perspective of the project developer the goal of the Peñas Blancas Hydroelectric project is to construct a 35.4 MW power plant to supply the country's energy demand at a competitive rate of return without the need to rely on thermal power sources. Therefore, the project will also contribute by offsetting greenhouse gas emissions that otherwise would be generated by ICE using thermal power plants, burning high sulfur diesel fuels and bunker oil.

The project is fully compatible with local and global environmental priorities such as the national commitment to expand the role of clean sources of energy in the national energy mix. In doing so, Costa Rica is seeking a less carbon intensive development track. ICE recognizes that any power development will have an environmental impact, but considers that Peñas Blancas is an example of seeking alternatives to mitigate the environmental impacts, as it has been demonstrated through the implementation of the Environmental Management Plan of the project. ICE is perceived as an environmental responsible entity by the greater Costa Rican society, including those segments of the society that live in the areas of influence of its generation projects.

Therefore, the main goals of the project in the medium and long term are:

- Contribute to meet the growing demand for electricity to fuel Costa Rica's development needs, based on locally available alternative resources instead of relying on imported oil to fuel thermal power plants without any aggregate value to the local economy;

- Reduce greenhouse gases emissions from the national interconnected electric system (NIS) that otherwise would have happen. In doing so it will contribute to the long-term mitigation of climate change and be eligible for the Clean Development Mechanism (CDM) of the Kyoto Protocol. The economic contribution in exchange of Certified Emissions Reductions will improve the financial structure of the project;

- Strengthening the national stock market and provide an attractive and secure investment opportunity to local and foreign investors;

- Provide a "win-win" opportunity where global environmental and national economic benefits can be generated through an integrated and mainstreamed approach to national sustainable development priorities.

1.4.2 Project Purpose

The purpose of the Peñas Blancas project is to contribute to meet Costa Rica increasing energy demand for economic growth through the generation of electricity based on renewable source instead of relying on imported oil, without any aggregate value to the local economy.

1.4.3 Project Activities and Results

Table 3 – Project activities and results

Activities	Results
Preliminary activities required prior to the construction of the project	• Technical studies required for the project (completed); • Final design of the project (finalized); • Environmental Impact Assessment (EIA) completed and approved by the Technical • Environmental t Agency (SETENA).
Emission of bonds to finance the project	• Bonds are emitted and $70 million dollars raised to develop the project; • ICE commits under a 13-year lease contract to pay the trust fund.
Construction of the project	35.4 MW hydropower facility constructed by ICE under a contract with the trustor. The plant is about to be commissioned and start operation.
Operation of the project	• An average of 164 GWh/year of clean and renewable energy will be delivered to the NIS to contribute meeting growing demand ; • An average of 87,826 tons of CO_2 per year is the reduction of greenhouse gas emissions that the project contributes in mitigating global climate change.
Completion of the Peñas Blancas trust fund	• ICE pays a lease to the trust fund throughout the (2002-2015); • At the end of the 13-year period, ICE will purchase the Peñas Blancas project from the trust fund; • Investors will obtain the expected yield on their bonds.

2 GHG SOURCES AND PROJECT BOUNDARIES

This Section provides a description of the GHG emissions sources included in the Peñas Blancas Hydroelectric project. Only emissions sources included in the project boundaries will be considered in the calculation of the baseline and monitoring of project emissions.

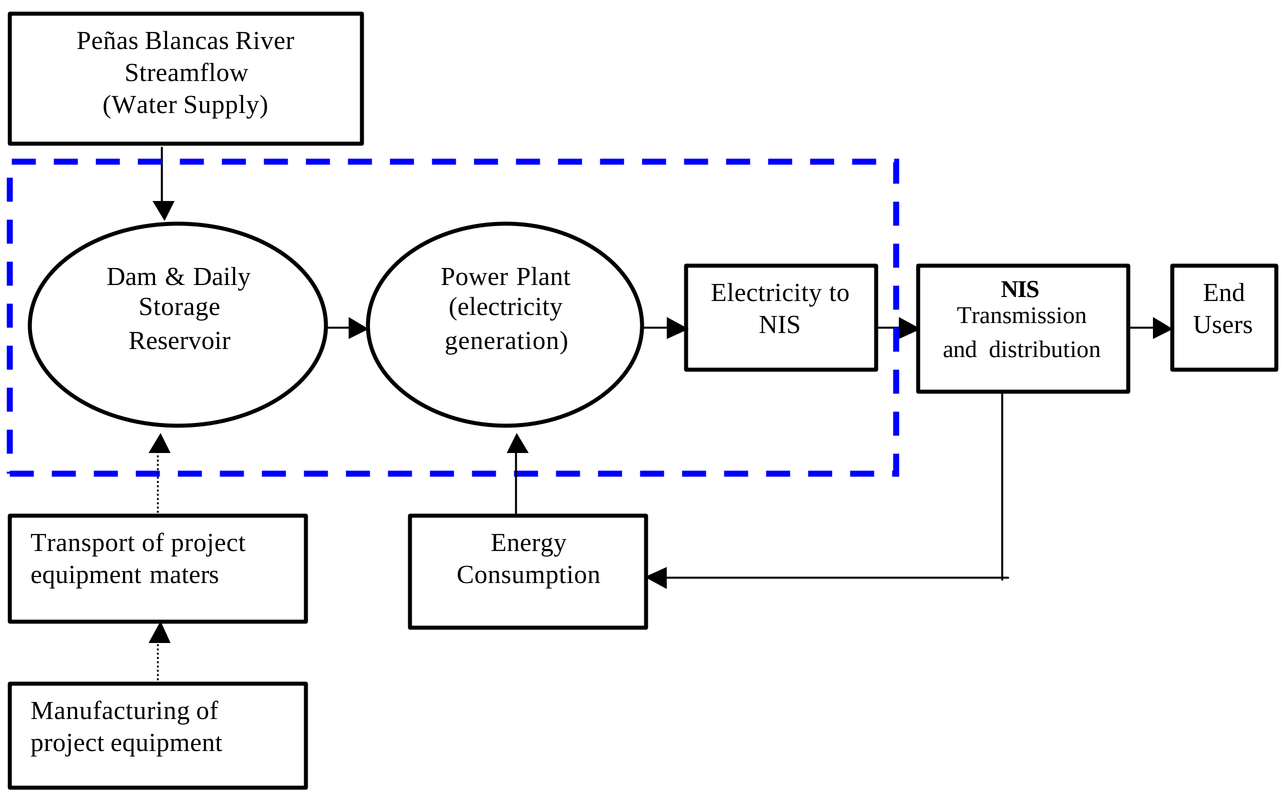
2.1 Flowchart and Project Boundaries

The project boundary is defined by the emissions targeted or directly affected by the project activities, construction and operation. It excludes emissions from activities beyond the control or influence of the project. Project boundaries also applies for the baseline scenario.

To achieve consistency in defining the project boundaries, two principles shall be respected. The principle of control, which implies that the project boundaries should be set in a way that they comprise all relevant emissions sources that, can either be controlled or influenced by the project participants and that are reasonably attributable to project activities. The second principle is that case, the relevant impacts on GHG emissions related to activities one step downstream and one step upstream of the project should be included within its boundaries

The project will add to the current situation of the NIS, the Peñas Blancas Hydropower Project, though it is likely to displace thermal power generation from existing facilities. Given the interconnectedness of the national grid, it is not possible to desegregate which plant is likely to be displaced. Therefore, the transmission and distribution of power at the NIS is out of the project boundaries.

Because streamflow is outside the control of the project, it is placed outside the project's boundary alluding to the principle. The project boundary for the purpose of emissions reduction calculations for the Peñas Blancas Hydroelectric project is given in the flow diagram below.



2.2 GHG Sources and Project Boundaries

In this section the potential sources of relevant GHG emissions within the project boundaries will be identified in order to distinguish between emissions that will and will not be accounted. This will be achieved through the assessment of the project activities within its boundaries. Project boundaries are the notional margins around which project emissions impacts are to be assessed. The project boundaries shall also apply for the baseline scenario.

The CERUPT guidelines for baselines and monitoring practices divide the sources of GHG emissions relevant for the project boundaries into on-site and off-site emissions that can both be subdivided into direct and indirect emissions. As a general rule only those emissions that are within the control of project participants should be included. The tables below identify the emissions and label them to which extent they are significant or not.

Emissions that are likely to be less than 1% of the total project emissions will be classified as insignificant and not accounted in the project. As total project emissions over 10-year crediting period are calculated at approximately 1,233,240 tons of CO2 equivalent, 1% amounts to 12,332 tons of CO2. A summary of sources of GHG emissions is shown in Table 4 below.

Table 4 –Sources of emissions and project boundaries

Sources	On Site	Off Site
Direct	• CO_2 emissions during the project construction (e.g. fuel use by trucks and machinery, clearing biomass prior to impoundment of small reservoir, etc.); • No emissions are expected during the project's operation and management.	• *One-step upstream:* Emissions related to the transport of construction materials and equipment to the project site; • *One-step downstream*: emissions related to grid losses due to transmissions and distribution of energy generated by the project.
Indirect	• None are expected	• Emissions during the manufacturing process of parts, supplies and machinery required for building the project (i.e. cement, electromechanical equipment, etc.). These are outside the control of the project and excluded; • Avoided emissions at the NIS by providing renewable power rather than having to use existing or build additional thermal power plants is accounted as a source of project emission reductions (positive leakage);

2.2.1 Direct on-site emissions

The direct on-site emissions sources can be divided into activities prior to and during the operation of the project. Since hydropower is a clean energy source there will be no GHG emissions that are directly related to hydropower generation. The exception is the construction phase needed to get the project up and running. During construction there will be direct on-site emission, mostly through the burning of fossil fuels by trucks and construction machinery. Biomass removed during project construction can also be a direct source of GHGs emissions at the site. This includes any biomass cleared prior to flooding the area of the small daily storage reservoir. The following activities have been identified as sources of direct on-site emissions:

Emission Sources	Description	Significance
Construction of the dam	Gravity dam on the Peñas Blancas River with a maximum height of 46 meters and a width of 203 meters. It will require 155,700 m3 of concrete	Insignificant
Tunnel	A 2,080 meter-long tunnel, 83% of which is reinforced with concrete (diameter of 3.9 m), the rest is reinforced with an armour shield (3.3 m diameter).	Insignificant
Oscillation Tank	47 m-high steel structure with an 11 m-diameter. On an octagonal concrete base (27,5 m por 27,5 m)	Insignificant
Penstock	Reinforced steel pipe 1,368 meters long, diameters range from 3.3-3.5 meters	Insignificant
Power Plant	700 m2 constructed area Generating equipment (two 17.7MW Francis turbines + two 17.64 MW generators)	Insignificant

2.2.2 Direct off-site emissions

Direct off-site emissions are those directly influenced by the project activity but that will occur outside the project area. This includes, in principle, one step upstream and downstream emissions. Although hydropower facilities do not produce emissions during the generation of electricity, there would be emissions related to grid losses due to the transmission and distribution of the energy generated by the project (one-step downstream).

In addition, the transport of construction materials and equipment to the project site would also be accounted. However, these are out of the project control and will not be accounted following CERUPT guidelines.

2.2.3 Indirect on-site emissions

The indirect on-site emissions identified are related to the use of energy for the operation of the power plant such as energy for cooling systems, lighting, ventilation, compressors, etc. The NIS will supply the energy. Therefore, to avoid double counting related emissions will be accounted at the system level and not at the project level.

2.2.4 Indirect off-site emissions

These emissions are related to activities that will occur outside the project boundaries and are not directly influenced by the project activity. Despite the electricity produced by the project will be fed into the grid and undoubtedly the presence of the project will change the patterns of energy dispatching at the NIS, shifts in production is considered a source of emissions reductions indirectly attributed to the project activities.

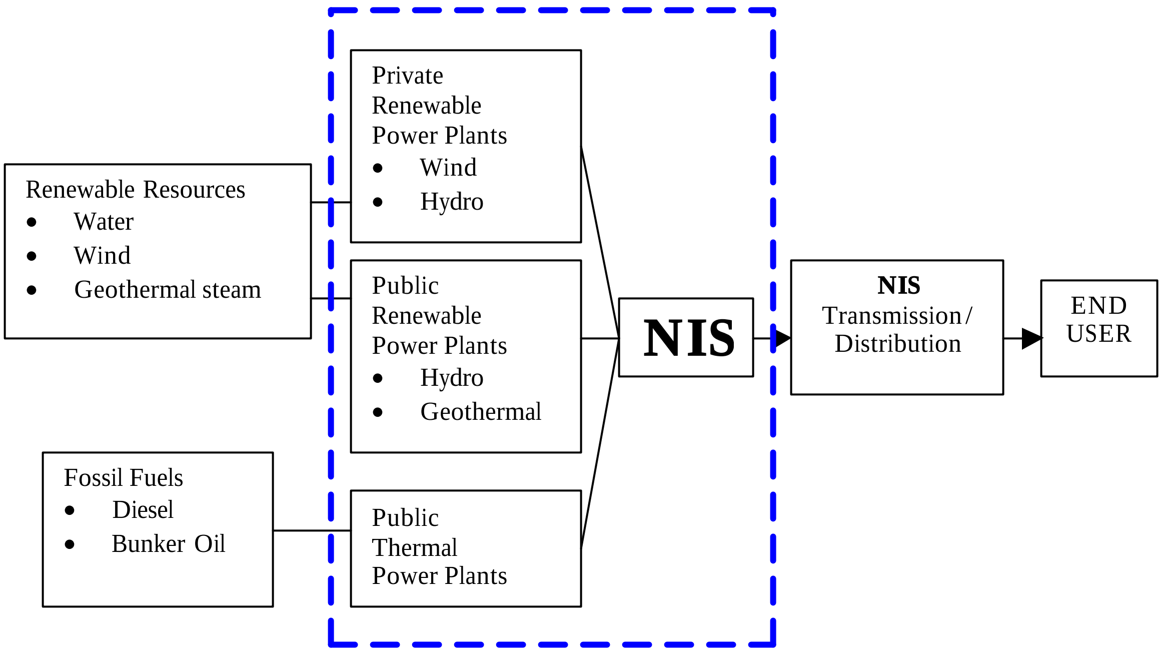
In addition, emissions during the manufacturing process of parts, supplies and machinery required for building the project (i.e. cement, electromechanical equipment, etc.). These are outside the control of the project and will not depend on the project activity level. Therefore, will not be accounted.

3 DESCRIPTION OF THE CURRENT DELIVERY SYSTEM

The Peñas Blancas Hydroelectric project will supply electricity to the grid. This Section explains the current delivery system of the National Interconnected System (NIS) that supply energy to the grid. Isolated systems and generation facilities not connected to the grid are not considered given that the project will not affect this scenario. Therefore, this Section describes the status and characteristics of the current Costa Rican interconnected electric system.

3.1 Flowchart of Current Delivery System

The current operation of the NIS provides the starting point for defining the framework for the baseline. The flow diagram below shows its current operation with its main components and connections.



Since project boundaries is defined by emissions sources directly affected by the project operation, for the CERUPT application purpose (e.g. Peñas Blancas HP, El Encanto HP and Rio Azul LFG Energy project) it will be defined by the system directly affected by the operation of the CERUPT projects.

Since all power plants at the NIS are potentially affected by the operation of the CERUPT projects, the project boundaries comprises, one-step downstream, the whole NIS. Therefore, covers practically the entire national territory. The operation of the CERUPT projects will have the same effect as of reducing generation from current and planned power plants at the NIS.

Public utilities (e.g. Peñas Blancas HP by ICE and El Encanto HP by CNFL) and a private generator (Rio Azul LFG Energy project by SARET Group) are respectively developers and/or suppliers for the purpose of the CERUPT application.

For the baseline it is assumed that the NIS is an isolated market without interconnections between Costa Rica and neighboring countries. In fact Costa Rica is already interconnected with the Central American countries, although only through single circuit 110 kV lines of limited transport capacity and currently sells hydroelectric surpluses (secondary energy) on an opportunity basis. This opportunity export does not, however, influence the NIS expansion plan.

3.2 Status, Adequacy, and Operation of Current Delivery System

The current delivery system of the NIS is composed of various generating power plants and distribution systems connected to the transmission grid comprising 97 per cent of the national territory. Various institutions are key players on the NIS, the major one being ICE. There are also various other power producers and distributors. As described in Section 1.3.1.1, there are various government institutions involved in the regulation of the NIS, including the Ministry of Environment and Energy (MINAE) and the National Public Services Regulating Authority (ARESEP). The current regulatory framework in the country does not follow the reform and privatization trends that have taken place in most of the countries of Latin and Central America. Private sector participation in the NIS is still quite limited compared to other countries in the region.

The existing generation facilities in the NIS have a total installed capacity of 1,645 MW of which 1,228 is hydro, 229 MW is thermal, 142 MW is geothermal and 46 MW is wind based. As evidenced by the distribution of installed capacity, Costa Rica relies heavily on renewable energy sources (86%). The largest power producer (76%) is the Instituto Costarricense de Electricidad (ICE), followed by private power plants (14%) and the Compañía Nacional de Fuerza y Luz (CNFL) (8%).

After opening the sector to private participation in 1990 under Law No. 7200 (subsequently modified in 1995 by Law No. 7508), about two-dozen independent generators and self-generators entered the market under limited conditions -- mostly to sell power to ICE and to distributors. These projects are limited to renewable energy sources and are capped by 20 MW power capacity (50 MW in case of BOTs)[2]. In addition to government utilities and the private sector there are also municipal entities and rural electrification cooperatives that generate power, mostly for distribution throughout their distribution grids. Table X below show the existing power plants comprising the NIS.

3.2.1 Distribution

The transmission component of the NIS if fully owned and operated by ICE. Distribution is mostly split between ICE (41%) and CNFL (38%). CNFL has developed its grid in the Central Valley of the country, mainly in the Greater Metropolitan Area. ICE has a much wider distribution network, covering urban and rural areas of the country.

Two municipal companies, ESPH and JASEC, also distribute power on a more localized basis. ESPH has its distribution network in the province of Heredia, mostly the urban center of the city of Heredia. JASEC works in the province of Cartago. In addition to the municipal companies there are four Cooperatives, created in the 1970's to increase the distribution of electricity in four rural areas

[2] (a) Law No. 7200 (1990) promotes small-scale exploitation of hydraulic potential and other renewable sources and allows private independent generators and self-generators using renewable energy resources to sell energy to the public electricity system via ICE. The law limited the size of the units to less than 20 MW and limited to 15% the aggregated installed capacity owned by independent generators. The law also required local ownership of at least 35% of the equity share in each project.

(b) Decree No. 7508 (1995) modifies Law No. 7200 by raising the limits for independent generators' participation to 30% of the total installed capacity in the system. It also raised the maximum size of the units to 50 MW. It also required that the concessions for new (alternative and renewable energy) capacity would be awarded under competitive bidding procedures according to bid price and a technical, economic, and financial evaluation of the bidder's proposed project. The decree authorized ICE to enter into international agreements for electricity transactions with other regional or state-owned utilities.

of the country: Coopelesca (in San Carlos), CoopeGuanacaste, Coope Alfaro Ruiz, and CoopeSantos. Together the municipal companies and rural cooperatives distribute the remaining 21% of electricity at NIS. Cooperatives and municipalities have traditionally purchased the power they distribute from ICE. However, recently some of the companies have started to generate a proportion of the power they distribute to reduce the purchases from ICE. All distribution networks, whether they are owned by municipalities, cooperatives, and utilities, are connected to the NIS and therefore form an integral part of the system.

Summary of characteristics of existing generation plants (2001)

1. HYDROELECTRIC PLANTS

Name	Installed capacity (MW)	Annual average generation (1982-1998) (GWh)	EE (kWh/m3)	Reservoir useful volume (Hmc)	O&M Costs Fixed ($/kW-year)	O&M Costs Variable ($/MWh)
ARCOSA (527 msnm)	372		1.03	1477.47		
Arenal	160	630		1605.00	17.50	-
Cachí	100	615	0.49/0.51	47.88	17.50	-
Corobicí	180	730			17.50	-
Garita	30	169	0.360	0.40	17.50	-
Smaller (3)	32	164		-	17.50	-
Río Macho	120	570	1.020	0.39	17.50	-
Ventanas Garita	100	456	0.540	0.66	17.50	-
Sandillal	32	120		4.82	17.50	-
Toro I	23	91		-	17.50	-
Toro II	66	277	0.870	0.23	17.50	-
Angostura	177	900	0.300	11.00	17.50	-
CNFL (4)	81	-		-	17.50	-
Private generation (Includes Coopelesca 8MW)	135	-				-
Subtotal	1236	4722				

2. THERMOELECTRIC PLANTS

Name	Effective capacity (MW)	Annual average generation (Last 5 years) (GWh)	Type of fuel	Specific efficiency (kWh/liter)	Maintenance rate (%)	Fixed O&M costs ($/kW-year)	Variable O&M costs ($/MWh)
Barranca	30	60	Diesel	2.57	8	17.00	1.81
Colima	14	43	Die./Bun. C	3.20	8	67.92	3.72
Moín Piston	26	30	Die./Bun. C	3.70	8	14.75	0.68
S.A. Gas	30	50	Diesel	2.50	8	62.42	1.35
Moín Gas	134	314	Diesel	2.98	8	8.23	5.98
Subtotal	234	497					

3. GEOTHERMAL PLANTS

Name	Effective capacity (MW)	Annual avg. historic generation (GWh)	Type of fuel	Specific efficiency (kWh/liter)	Maintenance rate (%)	Fixed O&M costs ($/kW-year)	Variable O&M costs ($/MWh)
Miravalles I	52.25	450		-	8	28.55	0.0
Miravalles II	52.25				8	28.55	0.0
Boca de Pozo	5.00	30		-	8		
Miravalles III	27.50				8		
Subtotal	137						

4. OTHER PLANTS

Name	Effective capacity (MW)	Annual avg. historic generation (GWh)	Type of fuel
El Viejo (Priv. Biomass Gen.)	4	6	Bagazo (sugar cane)
Aeroenergía (Wind)	6	22	
Tilarán (Wind)	20	70	
Tierras Morenas (Wind)	20	70	
TOTAL SNI	**1658**		

Notes:

1. Border prices at december 1999 level

2. Specific consumption at full load, diesel consumption assumed at 10248 kcal/kg, with specific weight of 0.832 kg/lt and C bunker of 10207 kcal/kg, with specific weight of 0.982 kg/lt.

3. Smaller Plants : 32.4 MW (Cacao+Echandi+Avance+Lotes+Pto. Escondido = 5.7 MW) (ESPH+JASEC = 26.7 MW)

4. Daniel Gutiérrez (21MW) + Brasil (27MW) + Others (33MW)

3.2.2 Pricing

In accordance with current regulations ICE must present tariff schedules for ARESEP's approval. ARESEP sets the prices for ICE's purchases from independent generators (for a 15-year contract term) based on the system's avoided costs, which is measured by the long run marginal cost (LRMC). LRMC is calculated by ICE on the basis of the least-cost expansion plan and must be presented to ARESEP for approval. LRMC as such is a parameter that represents different system products: a combination of energy (firm plus secondary) and capacity costs. ARESEP has developed tariff schedules that intend to remunerate energy and capacity charges in a way that better represents the value added to the system by these different products. Supply contracts based on such principles contain prices for peak and off-peak energy. Tariffs for power distribution are also set by ARESEP on the basis of requests by the power distributors.

3.2.3 System Operation

ICE is the main operator of the NIS, receiving power from generators, transmitting it through its grid, and reselling it to distributors or directly to end users through its distribution network.

Dispatch is based on each plant's "merit order", from lowest to highest marginal generation cost. Least-cost dispatching favors the operation of available generation sources with the lowest variable costs, or short-term marginal costs. Since thermal plants have significant fuel costs, low efficiencies and higher maintenance costs, are the most expensive plants to operate and therefore, operates at the margin and is part of the system reserve that is heavily dependent on run-off river hydropower plants.

In virtue of the above, the NIS is dispatched daily on the basis of economic parameters which dictate the convenience that run-of-river hydropower plants are positioned on the base of the generation load curve in such a way that they maximize their electricity output (baseload). Next in the system are hydropower plants with inter-annual reservoir capacity, namely Arenal and Cachí, which are dispatched with longer-term time criteria, usually one year. Therefore, plants with inter-annual storage capacity are located in the middle section of the generation load curve.

Facilities with modes of continuous production, such as geothermal power plants and PPAs with private producers are also dispatched along the lower section of the load curve. This means that thermal power plants are on the margin and only operate along the higher sections of the load curve, especially during peak hour demand.

During the dry season the production capacity of run-of-river hydropower plants is reduced, and thermal plants increase their energy output, moving to a lower position along the load curve (baseload).

Costa Rica's dispatch model means that thermal power plants have low plant factors, since they are only used when other production modes are not available, especially run-of-river hydro plants. Therefore, if during a particular time there were a decreased production by run-of-river hydro plants (i.e. during a drought period such as in El Niño years), thermal plants would fill the void up to their production capacity.

This means that a portion of current hydro installed capacity as well as future renewable additions to the generation mix do in fact substitute thermal capacity that is available but not used to its maximum capacity. If the difference between maximum thermal production and real production is calculated, it is possible to determine what proportion of thermal output is being substituted with renewable power plants.

3.2.4 Border Trade in Electricity

Costa Rica is interconnected with Panama, Nicaragua, Honduras, El Salvador, and Guatemala, although only through single circuit 110 kV lines of limited transport capacity. Costa Rica currently sells hydroelectric surpluses (secondary energy) on an opportunity basis. For instance, in 1999 Costa Rica sold 128 GWh to Honduras (60%), Panama (30%) and Nicaragua (10%). This opportunity export does not, however, influence ICE's expansion plan. Costa Rica exports only surplus hydropower and only after it has satisfied Costa Rica's own demand: in this situation the carbon intensity in the Costa Rican NIS is (near) zero.

The sale of hydroelectric surpluses opens additional room for substitution under the CERUPT application in Costa Rica, because energy exported by Costa Rica would substitutes thermal energy at the importing countries. However, emission reductions that might result from this export will not be claimed, because: energy exports are aleatory, and the applicable carbon intensity factors would correspond to those thermal units that would be operating in the margin at the same time the export is made and thus difficult to predict.

In this vein, the SIEPAC project is expected to develop a regional bulk supply market, construct a solid interconnection system and establish a regional regulator and a system operator/market administrator. It is foreseen that Costa Rica will participate in a regional power market that is being developed under an international treaty by the six countries in the Central American Isthmus. Complementing the 1996 treaty, the SIEPAC project financed in part by the Government of Spain and the Inter-American Development Bank, plans to upgrade the existing six-nation electrical network.

3.2.5 National Planning and Forecasting: ICE's Expansion Plan Policies

The Government of Costa Rica's strategies for the power sector is reflected in a national expansion plan, which is periodically updated by ICE. ICE's expansion plan for the Costa Rican power sector follows Government policies regarding the use of resources, provides information to the Government regarding demand and supply, evaluates financial resources needed by the sector and gives the price signal to potential private investors in generation. In addition, sets the basis for the application of electricity tariffs. The sector development is planned in isolation from other countries, even though the six countries in the Central American Isthmus are progressing towards a higher degree of integration, through the above mentioned SIEPAC project.

Planning Criteria

ICE's overall expansion planning objectives are to supply demand at minimum cost, within environmental constraints. Planning tools aim at minimizing a function that represents the present value of a stream of: (i) annual investments in generation plant, (ii) fixed and variable operations and maintenance costs of the existing system and of the new installations, and (iii) the costs of non-served energy. Investments and operations costs reflect international market prices and are expressed in constant dollar terms.

Projects developed by ICE and those sponsored by other companies or private investors are evaluated under equal conditions. Resources considered include indigenous and imported resources. Costa Rica has no hydrocarbon resources and the opportunity of bringing gas to the region is considered beyond the planning horizon.

Costa Rica has a large economically feasible hydro potential, estimated at 8000 MW, of which only one eighth is currently exploited. ICE is responsible for the evaluation of hydraulic resources for which potentially economic and technically feasible projects are evaluated with a progressive degree of detail until they are ready for implementation. Selected projects with properly advanced evaluation are proposed for the expansion plan. Those with a lower degree of definition are kept for the long term. Selected thermal options with technologies and sizes compatible with the existing system are considered within their environmental limitations. Geothermal and wind options are also considered, though these resources are limited.

Given the high preponderance of hydro in the system, the reliability criteria are based on energy requirements. ICE's reliability criteria are based on full supply of demand 95% of the time,[3] which is an international practice. Reliability is evaluated by simulating the system operations with a 30-year (1967-1996) historic series of monthly flows for each existing hydroelectric plant. Additionally, to evaluate differences in reliability between configurations, a certain value is given to the non-served energy.

The planning horizon is set to about 16 years and divided in three periods:

(a) **Short term period.** 2001-2006, in which the plan is almost defined. This is because electricity generation plants have long gestation periods that include, inter alia, preparation of final design and bidding documents, securing financing, and obtaining environmental permits.

(b) **Medium term period.** 2007-2012, in which the candidate generation plants are submitted to optimization, the best sequence of projects is searched for, and finally chosen on the basis of least-cost principles.

(c) **Reference period.** 2013-2018, in which a number of projects, some of which may still be at a feasibility stage, are submitted to the optimization plan. This segment of the plan is far from firm due to the uncertainties associated with the demand growth and feasibility of the projects, and is aimed at providing a reference frame for future studies.

Models

Planning tools used by ICE are modern and state-of-the-art, and are well adapted to the particular characteristics of the Costa Rican system and hydrology. ICE uses three mathematical models for expansion planning, known as LOGOS[4] (developed by EdF of France for ICE), SUPER-OLADE and SDDP. LOGOS is a stochastic dynamic programming model, which simulates the system operations under a series of hydrological conditions. It permits the selection of an optimum expansion plan by evaluating the total development cost (investment, plus operations costs plus cost of non-served energy) by an iterative trial-and-error simulation process. SUPER-OLADE is a complex modular model recently developed by OLADE[5] and IDB extensively used in Latin America. It is basically a stochastic dynamic programming optimization model (Module MODPIN) though other modules help in the preparation of demand forecasts and conservation (Module DEM), thermal generation simulation (Module COSMOS), financial requirements (Module FIN), and environmental restrictions (Module AMB). SDDP[6] is a well-known stochastic simulation model developed by Power Systems Research (Brazil). It has the capability to analyze operational programs for inter-annual reservoir management.

The optimization process is based on the evaluation of an objective function. The sum of investments in new plants, plus the operational cost of the system plus the cost of the non-served energy, and the identification, through dynamic programming, of the path, among a large number of

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3 More precisely, ICE reliability criteria establish that within the 95% of the hydrological series simulated, the deficit in any given month could not exceed 2% of the energy demand for that month.

4 Logiciel de Gestion Optimal du Systeme Electrique.

5 Latin American Energy Organization, a Governmental organization based in Quito.

6 Stochastic Dual Dynamic Programming.

possible configurations, that result in the minimum present value of the objective function. The cost of the non-served energy represents the foregone benefits to the society as a whole of not having the energy when it is needed, and allows for configurations that have different reliability levels to be placed on the same footing.

The interactive use of the above planning tools permits that ICE makes an exhaustive analysis of expansion options. ICE develops expansion sequence options by using LOGOS and SUPER-OLADE models. These sequences are analyzed to ensure that they comply with security of supply criteria, and then those sequence options that comply with the reliability criteria are evaluated in terms of present value to select the optimum plan.

The planning horizon is divided into three periods. The period 2001-2007 is characterized by the execution of projects that are either in construction or well advanced in terms of the decision-making process (they have a final design, environmental approval and have secured financing). The period 2008-2012 where the least-cost sequence of projects is selected from a set of candidates that are sufficiently developed to consider their data as firm and the period 2013-2018 considered as a reference. Projects selected through optimization in this period have a lower degree of definition and are selected for additional studies.

Economic Parameters

Economic parameters used by ICE are within normal ranges. Prices are expressed in constant terms and reflect 1999 price levels. Figures for this report represent market prices though ICE uses shadow pricing methods for analyzing special issues such as preferences for indigenous resources. A discount rate at 12% p.a. is widely used for electricity planning and IBRD uses this figure currently. A critical factor in electricity planning is the price of fuels which is always difficult to project given the volatility of prices. ICE uses international prices and adopts mainly FOB (free on board) price projections prepared by the US Department of Energy (US DOE) and on this basis develops CIF (cost, insurance, freight) and plant prices with ICE' s own database. Fuel prices currently used by ICE assume a steady increase in FOB crude oil prices from US$ 23.45 for 2001 to US$ 28.00 by 2020. With regard to the cost of non-served energy ICE uses a value of US$ 1.20/kWh, which is considered within international practice.

Demand Projections

ICE prepares the demand projections based on an econometric sectoral model that desegregates demand by consumption classes (domestic, industrial, large industrial, general and public lighting). Variables considered are GDP, other economic indicators, demographic variables and energy prices. This type of model is widely used in the electricity power industry.

System operations simulation requires representing the current and future load curve and its seasonal and hourly variations. The NIS in Costa Rica shows two peaks: at noon – due to extensive use of electricity for cooking purposes – and in the evening. Given the scarcity of other fuels, ICE assumes that the use of electricity for cooking will continue in the future and thus the system load factor,[7] at 65%, will not vary within the planning horizon.

The detailed system operations are simulated with a set of hydrological data that covers the period 1967-1996. Dispatch is based on each plant's "merit order", from lowest to highest marginal generation cost and results are recorded plant-by-plant, month-by-month. These are expected values of the results of simulating the operations of the system for each year under the full set of hydrological data.

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[7] Ratio between the average power demand (yearly energy consumption divided by the hours in the year) and the maximum observed demand (peak demand).

4 KEY FACTORS INFLUENCING THE BASELINE AND THE PROJECT

4.1 Legal

The energy market in Costa Rica is highly centralized and private sector participation in generation israther low compared with others countries in the Central American region.

The legal risk that would affect the baseline is power market liberalization within the region. In this regard, a bill sent to the Congress by the Government in early 2000, that would unbundled ICE's activities and would create a bulk local supply market, failed to be approved and was withdrawn by the Government in view of opposition. Currently any initiatives to reform the sector are on hold. Therefore, power market liberalization risk is considered to be low in Costa Rica, especially during the project 10-year crediting period.

The expectation is a continuation of the "status quo", where the government will keep a centralized control and ownership of most elements of the energy market such as dispatch and transmission in addition to the bulk of energy generation and distribution of the NIS. This centralized control is likely to be strengthened because of the political agreement to transform ICE in a more flexible entity to continue its leading role in the local electricity market.

Despite there is a new Administration, it is unlikely that it would re-open the process. It is widely acknowledged that, at least in the short-term, proposing liberalization of the energy sector means incurring in a very high political cost because the strong opposition. If for any reason in future the government could proceed with market liberalization, it is unlikely to affect the baseline scenario and the expected ERs attributed to the CERUPT projects.

First, electricity generation plants have long gestation periods and second, precedents in similar contexts in Latin America demonstrate that market liberalization leads to a "thermification" of the system. A "thermification" is a tendency of increasing the penetration of thermal power in the generation mix of the interconnected electric system. Such a situation for the particular context of the CERUPT projects would allow for a more carbon intensive baseline. Therefore, not considering market liberalization scenario, which is highly unlikely in the short and medium-term, is a conservative approach in nature.

In addition to the liberalization of the electricity market that has lead to a thermification of our neighboring countries, the SIEPAC is an important element in the context of the sectoral baseline in Costa Rica.

The SIEPAC is a treaty for the creation of a regional common market. It is expected to build a regional interconnection system and develop a regional bulk supply under a competitive market. It will bring opportunities and threats to the local electric market.

It will enhance exporting firm renewable power to any part of the Central American Isthmus. On the other hand, under a competitive market and favourable prices of fossil fuels, it could enhance importing thermal power from regional generators without any aggregate value to our economy.

In this vein, CERs trading is expected to mitigate this risk by enhancing the competitiveness of the local renewable energy throughout the region. This is especially important considering that more than 50% of the region's population does not have access to electricity and that it is mostly generated by the combustion of fossil fuels.

4.2 Economic

In some respects, Costa Rica's development has been typical of other Latin American countries; in the early stages of development it concentrated in productive efforts on specializing in a few agricultural crops. In the 1960's, under the impetus of import substitution, it began an insipid industrialization under the protection of heavy tariff barriers (formed around the Central American Common Market). In the 1970's, it acquired an increasingly heavy external debt load that lead to complete economic breakdown, followed by a period of painful recovery and structural adjustment in the 1980's. In the 1990's it shifted its economic policies to services and export promotion, both more intensive in using energy.

Assuming that development is a key element in estimating future demand of energy, economy growth is the driving factor of ICE's expansion plan. Table below summarizes the volatility of the national GDP during the last 7-year period.

Costa Rica's GDP	1995	1996	1997	1998	1999	2000	2001
GDP (Annual Variation (%)	3.9	0.9	5.6	8.4	8.2	2.2	0.9

Source: Costa Rica's Central Bank statistics

However, electricity demand has grow steadily at a rate of 5 to 6% per year in the period 1990-2000 and electricity service coverage has reached 95% of the national territory. In accordance with studies developed by ICE, demand is expected to grow at an average rate of 5.2% per year during the period 2001-2016. During this period, demand for power capacity is expected to grow by 1,362 MW, from 1,174 MW in 2001 to 2,536 MW in 2016 and energy demand will grow by 8,434 GWh/year (from 6,750/year GWh in 2001 to 15,234 GWh/year in 2016).

Results of this planning process show that to meet demand in the period 2002-20016 installed capacity must grow from the current 1,237 MW to 2,536 MW. New installations will consist according with the expansion plan of 1,414 MW of hydro plants, 167 MW of thermal plants (when discounting decommissioning of old units), 74 MW of geothermal plants and 60 MW of wind farms.

It can be noted that thermal penetration at the energy mix of the NIS is expected to grow in relative terms with respect to the current operation mode. Despite still representing a small proportion of the total capacity, this indicates that the potential for displacing thermal energy is not expected to change during the 10-year crediting period.

However, to face the growth in demand, the expansion plan calls for the installation of approximately 1,300 MW during the next 15-year period. This plan requires yearly investment of approximately US$ 100 million per year and represents a significant expansion compared with previous periods. In this regard, ICE has accumulated a very high level of debt. ICE's hydroelectric expansion plan during the last two decades has absorbed a large amount of the nation's resources. A significant percent of the entire public external debt and the nation's debt service payments has gone to the energy sector.

Therefore, financing the cost of the expansion plan is ICE's most important challenge to accomplish its objective. Despite most of the expected power plants will be developed by public utilities and although public sector energy strategies favor the use of indigenous renewable sources, the investment capability of the sector dictates that it will favor in future thermal power plants with a lower capital investment cost. This is a risk element that would conservatively affect the sectoral baseline during the 1-year crediting period.

4.3 Political

The Government of Costa Rica articulates a clear policy in support of sustainable development. In the energy sector those policies are oriented to promote the sustainable use of domestic energy sources according to requirements of the expected demand and guarantee long term least cost energy production for the national economy.

With the regional power sector gradually reforming in the direction of greater private sector involvement, it will be increasingly difficult to continue to favor renewable sources under a conventional least cost planning approach. The shift to private financing can have a substantial impact on the competitiveness of the renewable energy because of their high initial capital costs. Under a regional competitive market and with favorable prices of fossil fuels, regional thermal generators will threaten the national market. Thus, for Costa Rica to continue planning new renewable energy sources, its incremental cost must be covered by CERs sales. Therefore, new renewable additions to the system should be treated as additional and not part of the baseline.

Furthermore, Costa Rica has been a leading advocate of the United Nations Framework Convention on Climate Change (UNFCCC) and has ratified its Kyoto Protocol. Since 1995, Costa Rica has been involved in the development of market oriented instruments to mitigate the climate change and has clearly being a leader in assisting the implementation of flexible mechanisms adopted by the UNFCCC. Through the Costa Rican Office on Joint Implementation (OCIC) as the national designated authority for the CDM, there is an adequate technical support for CDM project related activities as well as political support to eligible CDM projects.

The volatility of the energy consumption, the accelerated growth of the required power capacity and related reserves, in addition to the potential increase in using thermal energy with related implications to the national economy are elements of concern for baseline adjustments.

4.4 Socio-Demographic

As with GDP growth, demographic growth forecasts play a key role in projections of energy demand. Population increases and per capita energy consumption level are driver of the demand at the NIS. Demographic variables are therefore considered as an important element of the ICE's expansion planning methodologies.

The United Nation's projection for demographic growth in Costa Rica does not suggest a reduction in growth rate in the short-term. On the contrary, population is projected to reach 6 million by 2030. Furthermore, per capita energy consumption level is likely to grow.

Despite an overestimation of demographic growth would affect the baseline and the CERUPT projects' ERs, especially if future energy demand is lower than expected, ICE uses a conservative approach to avoid installing capacity in excess while always maintaining a safety reserve margin.

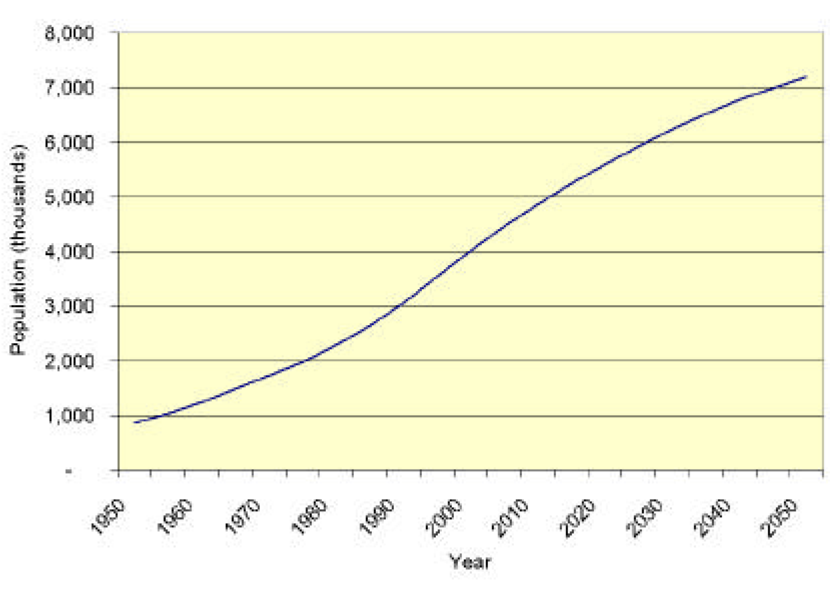


Figure – Costa Rica's Population Growth 1950-2050: Real and Forecast

4.5 Environmental

Stakeholders' opposition to a project on environmental grounds is a serious risk with detrimental consequences. In this regard, Costa Rica's legislation requires a previous Environmental Impact Assessment (EIA) for the development of hydroelectric projects. The approval of the EIA is required prior to the initiation of the construction phase.

ICE completed an EIA for the Peñas Blancas Hydroelectric project that was approved by the National Environmental Secretariat (SETENA), the technical competent authority responsible for overseeing the integrity of the environment. SETENA operates within the Ministry of Environment and Energy, the rector entity in the sector.

The outcome of the EIA was that the project would cause relatively few adverse impacts. Furthermore, it was concluded that the positive socio-economic impacts of the project would outweigh the adverse local impacts. The main negative impacts are temporary in nature, as they will take place during the construction phase. Construction is already in an advanced stage, and commissioning is expected for the second half of 2002, reducing considerably the risk of opposition.

In order to mitigate the remaining negative impacts, an environmental management plan has been conceived and will be monitored. Throughout the operation of the project, SETENA requires periodic reports by an independent environmental auditor who is responsible for overseeing the compliance with the established environmental management plan of the project. For further information refer to the summary of the EIA of the Business Plan.

Public consultation has been an important part of the Peñas Blancas project development. Since ICE has followed a consultative process with stakeholders at various stages, the local communities backed the project from the outset. The very mission of ICE, which is contribute to the social and economic development of the country, is interpreted internally, to provide social support to the communities surrounding their projects. ICE is perceived as a responsible environmental entity by the greater Costa Rican society, including those segments of stakeholders living in the area of influence of its projects.

Although ICE has been spared from public opposition to new hydroelectric developments, it is uncertain that this tendency will continue in the near future. There have been expressions of concern by various NGOs with regard to two hydroelectric projects proposed by ICE, Cariblanco and Boruca. ICE is aware and strongly committed to work with the stakeholders backed with local improved expertise on environmental assessments and impacts mitigation, to try to overcome potential risks related with hydroelectric projects and local communities.

Another potential source of environmental risk is change in land use within the project's watershed. Currently the Monteverde Biological Reserve and Monteverde Conservation League own a majority of land in the watershed. Both are non-governmental conservation organizations who purchased forested land for conservation purposes. It is unlikely they will allow for any land use changes in the watershed, which is currently under forest cover for the most part. If for any reasons there was a deforestation threat in the future, ICE will to intervene to ensure the watershed remains forested. Costa Rica's environmental and forestry legislation currently provides sufficient ground on which to rely to prevent a deforestation threat.

4.6 Technical

The project will use standard technology for hydropower projects worldwide. Francis type turbo machinery has been installed in several projects of similar size (in terms of size of units, rotational speeds, water design flows) in the country. There is already local capacity to support this type of technology within ICE, as well as a sound presence of supplier commercial chains in the country. Furthermore, operation of projects using the technology in Costa Rica has demonstrated it is very reliable and has very few forced outages.

In addition to the technology and design features, the location of the project itself was chosen after careful consideration of the relevant geophysical, environmental and other characteristics of the region. ICE's five decades in developing power projects in Costa Rica are proof of the solid capacity the institution has developed through many years of learning to cope with the particular circumstances of the local context.

The Peñas Blancas watershed receives a high annual precipitation of 4,600 mm per year. Hydrological monitoring in the watershed has been ongoing since the late 1970's, when ICE first started exploring the hydropower capacity of the watershed. A series of hydrological analysis were carried out in order to choose the best project alternative and later on, the most adequate project design.

Given that hydrological risk is extremely important for run-of-river hydro projects, it was explicitly taken into consideration and factored in during the conceptual and design phases of the project by ICE. The studies done included sensitivity analysis to optimize project design in order to minimize risk according to current best practices.

In addition, the adverse impacts of climate variability and change for example, would have a serious impact on project's and baseline performance. Nevertheless, the environmental integrity of the instrument is guaranteed on the aggregate during the 10-year crediting period.

5 IDENTIFICATION OF THE MOST LIKELY BASELINE AND THE ASSOCIATED GHG EMISSIONS

On the basis of the project approach described in Section 1, the project boundaries given in Section 2, the information on the current delivery system shown in Section 3 and key factors influencing the baselines identified in Section 4, the most likely scenarios for the baseline are described below. In addition, based on the analysis of different reference scenarios (e.g., what would happen in the absence of the project) the baseline for the CERUPT projects was defined and related emissions calculated.

5.1 Selection of Baseline Methodology

The baseline selection method is used to justify the choice of the baseline. For this application, the *Scenario Analysis* method was considered (e.g. the most probable scenario of what would happen in the absence of the project). This approach is consistent with Decision 7/CP.7 Annex on "Modalities and procedures for CDM" paragraphs 43 and 44 dealing with additionality and baseline respectively.

Since baseline is the scenario that reasonably represents the anthropogenic emissions of GHG that would occur in the absence of the proposed project activity, in choosing a baseline one of the following approaches would be selected (ref. Decision 17 C/CP.7, Annex on "modalities and procedures for CDM" Paragraph 48):

(a) Existing actual or historical emissions, as applicable; or
(b) Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment; or
(c) 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.

5.2 Presentation of Baseline Scenarios

The selection of a baseline scenario against which the project emissions are measured is one of the most important elements for claiming ERs. In this regard, the CERUPT Guidelines require the development of more than one baseline scenario, all of them including probable future scenarios.

In the long run, emissions of the NIS are determined by ICE's expansion plan, which is known and presented below. In the short term, emissions of the NIS are determined by ICE's dispatching decisions, which may include a number of low carbon-emitting plants. ICE's dispatching method is known and can be modeled in the absence of the CERUPT projects, allowing for the definition of the baseline.

Therefore, the baseline will be based on ICE's expansion plan for the Costa Rican power sector (see Table 7). Procedures and criteria adopted by ICE in preparing its expansion plans are detailed in Section 3.2.5 and results to supply demand to the NIS for the period 2002-2016 are summarized in Table 5 in Section 5.3.1.

The following three scenarios will consider:

Continuation of the Current Situation:

The performance of all existing operational power plants (e.g. plant factor, fuel type and heat content, and technology type and efficiency) would define the continuation of the "status quo" baseline scenario. Being the "status quo" scenario, emissions given by the carbon emission factor related to the current mix of thermal power plants operating at the NIS.

The calculation is based on the weighted-average carbon emission factor of the existing thermal power plants and related output during the reference year (2001). This scenario assumes that the existing characteristics of current operational thermal power plants would remain constant over the 10-year crediting period.

Scenario of future additions:

The performance of all expected thermal power plants additions to become operational at the NIS would form the scenario of future additions. Therefore, the baseline scenario comprising emissions projected ex-ante is constructed based on the performance of expected thermal power plants additions.

The calculation is given by the average carbon emission factor of the mix, using expected data on the performance of future thermal power plants additions and related output. These new additions have to become operational after the decommissioning of the current operational thermal power plants. This approach is more conservative since new and more efficient technology is expected in future

Scenario of current and future additions:

This is a more realist baseline scenario since it will concomitantly reflect the current and the expected mix of thermal power plants operating at the NIS during the 10-year crediting period. Therefore, the baseline scenario comprising emissions projected ex-ante is based on the performance of current and expected operational thermal plants at the NIS and the weighted-average carbon emission factor of the mix. The projection is based on the ICE's expansion plan (2002-2016).

The calculation using expected data on the performance of current and future thermal power plants and related outputs according with the simulation of the NIS without the CERUPT projects is summarized in the following Sections.

5.3 Calculation of Baseline

5.3.1 Model Background

ICE to optimize the NIS operation currently uses the Stochastic Dual Dynamic Programming (SDDP) model. The SDDP developed in Brazil by Power System Research is extensively used and has been licensed by utilities and agencies of several countries in Europe (Spain, Norway, etc.), Central (for the interconnection of the six Central American countries) and South America (Argentine, Bolivia, Brazil, Chile, Colombia, etc.).

This model is used for optimizing dispatches on a monthly basis, for short and long term planning horizons. The model takes into account different aspects represented in detail such as reservoir operation (turbining, spillage, filtration, etc. along complex cascades), inflow uncertainty, thermal plant operation (efficiency curves, fuel limits, start-up costs, multiple fuels, etc.), given demand in the form of a load duration curve, resource mix and fuel cost.

The data requirement to run the SDDP model includes the modeling of existing storage and run-of-river hydro plants specified explicitly by synthetic inflow series. Individual capacity, efficiency, cost of generation outage rates, forced and maintenance model thermal plants. The dispatch priority is first, run-of-river; second hydro plants with minor regulation; third hydro plants with multi-annual regulation; fourth marginal thermal plants based on operation costs. For dispatch optimization the objective function is minimizing the fuel, operation and maintenance costs for a given year.

The SDDP model has two main modules. The Hydrological module that is used to determine the weekly flow of existing and future hydroelectric power plants under different hydrological conditions, explicitly considering synthetic inflow series (35) for each power plant for each month of the year based on hydrological data (1965-1999).

The SDDP then using the Operative Planning module optimize the dispatch of the NIS taking into account inflow uncertainty through multivariate stochastic inflow models which represents both spatial and time dependence to simulate the operation of the system on a monthly basis. The dispatch in Costa Rica is made for 5 blocks and simulation runs can be made for 20 years consecutively or any selected year or period.

The ICE staff uses SDDP to assess various needs such as fuel requirements for future years, fuel costs, and power plant capacity factors. The result of the simulation shows, for a given year under given operational constraints, how often each power plant will run (capacity factors) and what the resulting fuel consumption and costs will be.

The SDDP model was used to optimize the operation of the NIS for the baseline case, based on the expansion plan developed by ICE, without considering the CERUPT group of projects (see Table 7 in Section 5.3.4). The results of the optimization are summarized in Section 5.3.5.

The CERUPT application intends to modify the carbon intensity of the energy supply in Costa Rica through the support for low or zero carbon emitting power plants – and this modification is the source for the ERs.

Therefore, to estimate the ERF it is crucial to determine the amount of electricity on the grid that will be displaced by the CERUPT group of projects. However, only part of their power output will avoid emissions at the grid and more than one particular technology or fuel used will be displaced.

In virtue of the above, the CERUPT projects ability to displace thermal generation at the NIS was also assessed using the SDDP model. This ability was determined by simulating the NIS including the energy output of the three CERUPT projects (see Section 6.3).

5.3.2 NIS Demand

The NIS' demand for the year 2001 was 1,176 MW and annual electricity consumption 6,719 GWh. In accordance with the national expansion plan (2002-2016) developed by ICE, demand is expected to grow at an average rate of 5.2% per year during the period 2002-2016. Projected maximum demand and annual energy demand (at a generation level, which includes consumption and losses) is shown in Table 5 below.

Table 5 – NIS Demand Projections

Year	Energy	Power	Growth
	(GWh)	MW	(%)
2001	6719	1176	
2002	7128	1248	5.74%
2003	**7512**	1315	5.11%
2004	**7921**	1386	5.16%
2005	**8343**	1460	5.06%
2006	**8845**	1548	5.67%
2007	**9356**	1638	5.47%
2008	**9888**	1731	5.38%
2009	**10448**	1829	5.36%
2010	**11035**	1931	5.32%
2011	**11652**	2039	5.30%
2012	**12300**	2153	5.27%
2013	**12981**	2272	5.24%
2014	**13696**	2397	5.22%
2015	14446	2528	5.20%
2016	15234	2666	5.17%

5.3.3 Current NIS Facilities

Expansion planning builds on the existing system, whose investments are considered sunk costs. The existing (2001) generation facilities in the NIS have a total installed capacity of 1,645 MW of which 1,228 is hydro, 229 MW is thermal, 142 MW is geothermal and 46 MW is wind based. During the planning horizon several thermal units with a total capacity of 74 MW will be decommissioned at the end of their useful life. The existing facilities in the year 2001 (capacity and average generation) are listed in Table 6 below.

Table 6 - Existing Generation Plants at the NIS (2001)

Name	Capacity (MW)	Energy (GWh)
A. Hydroelectric Plants		
Arenal	160	629
Cachi	100	618
Corobici	180	730
Garita	30	170
Minihydros	28	164
Rio Macho	120	576
Ventanas-Garita	100	462
Sandillal	30	120
Toro I	24	96
Toro II	60	268

Name	Capacity (MW)	Energy (GWh)
Angostura	180	910
CNFL (three plants)	81	383
IPPs	128	737
Total	**122 1**	**5893**
B. Thermoelectric Plants (1)		
Barranca Gas	30	42
Colima Diesel motors	14	32
Moin (diesel motors)	26	27
San Antonio Gas	30	33
Moin (Gas)	129	246
Total	**229**	**380**
C. Geothermal Plants		
Miravalles I	55	526
Miravalles II	55	300
Boca del Pozo	5	3
Miravalles III	27	147
Total	**142**	**978**
D. Wiind Farm Projects		
Privave Wind Farms	46	183
Total	**46**	**183**
Grand Total	**163 8**	**7434**

(1) Thermal plant generation correspond to ten-year average

5.3.4 NIS New Additions

Candidates for generation system expansion are a set of hydroelectric projects, one small geothermal project, two small wind power projects and generic thermal plants. The characteristics of the national expansion plan prepared by ICE are presented in Table 7 below.

Table 7 - National Expansion Plan (2002-2016)

Year	Demand				Supply
	Energy (GWh)	Growth (%)	Power (MW)	Growth (%)	Generation Projects
2001	6750		1174		
2002	7128	5.6	1237	5.4	Tejona Wind Power (20 MW) CNFL Gas Turbine TP (2 X 36 MW) Cote HP (6.3 MW)
2003	7512	5.4	1299	5.0	Upgrade Garita HP (10 MW) Chocosuela II and III (20 MW)
2004	7921	5.4	1366	5.2	Upgrade Cachí HP (10 MW) Miravalles V GP (19 MW) Chorotega Wind Power (8.4 MW) Vara Blanca Wind Power (9.6 MW) BOT HP (89 MW)
2005	8343	5.3	1435	5.1	Combined Cycl e Barranca I (60 MW)

2006	8845	6.0	1516	5.6	Combined Cycle Barranca II (60 MW) P.H. Cariblanco (75 MW) Phase-out Barranca TP (30 MW)* Phase-out San Antonio TP (30 MW)* Phase-out Moín TP (26 MW) Phase-out Colima TP (14 MW) Demand Mangement P. (9.5 MW)
2007	9356	5.8	1599	5.5	Pirris HP (128 MW)
2008	9888	5.7	1685	5.4	Wind Power P. (1x20 MW)
2009	10448	5.7	1775	5.3	Las Pailas GP (1 x 55 MW)
2010	11035	5.6	1870	5.4	Pacuare HP (156 MW) Wind Power P. (1x20 MW)
2011	11652	5.6	1969	5.3	MSDM TP (1 x 20 MW)
2012	12300	5.6	2072	5.2	Boruca HP (832 MW)
2013	12981	5.5	2180	5.2	*
2014	13696	5.5	2293	5.2	*
2015	14446	5.5	2412	5.2	Toro 3 HP (50 MW)
2016	15234	5.5	2536	5.1	MSDM TP (1 x 20 MW) Gas Turbine TP (1x35 MW)
HP – Hydroelectric TP – Thermal GP - Geothermal					

Source: ICE's Electricity Planning Department (August, 2002)

5.3.5 Simulation of the NIS Operation (Baseline)

ICE to optimize the NIS operation currently uses the Stochastic Dual Dynamic Programming (SDDP) model. Therefore, the detailed system operations of the NIS given by the ICE expansion plan are optimized with a set of hydrological data that covers the period 1967-1996.

Dispatch is based on each plant's "merit order", from lowest to highest marginal generation cost and results are recorded on a plant-by-plant, month-by-month basis. These are expected values based on the results of simulating the operations of the system for each year under the full set of hydrological data. The result of the simulation shows, for a given year under given operational constraints the output of the thermal power plants.

Results for each operational thermal plant, current and new additions, are given in Table 7 below. It can be noted that thermal generation will increase in the short term from 1% of demand in 2002 to 9% by 2016.

Table 8 –Projections of Thermal Generation under ICE's Expansion Plan (GWh)

Year	Cycle	Motor 1	Motor 2	Turb 1	Turb 2	Total (GWh)	Total %	NIS (GWh)
2003	0	0	98.3	164.2	9.8	272.3	4	7,512
2004	0	0	82.8	298.4	17.1	398.3	5	7,921
2005	232.2	0	0	261.8	12.8	506.8	6	8,343
2006	494.8	0	0	247.1	0	741.9	8	8,845
2007	479.8	0	0	287.9	0	767.7	8	9,356
2008	535.8	0	0	379.4	0	915.2	9	9,888
2009	563.2	0	0	442.6	0	1005.8	10	10,448
2010	513.2	0	0	388.8	0	902	8	11,035
2011	475.8	70.9	0	458.2	0	1004.9	9	11,052
2012	190	27.9	0	109.4	0	327.3	3	12,300
2013	223.5	32.3	0	138.3	0	394.1	3	12,981
2014	445.9	70.1	0	313	0	829	6	13,696
TOTAL	**4,154.20**	**201.20**	**181.10**	**3,489.10**	**39.70**	**8,065**		153,057

5.4 Calculation of Baseline Emissions

5.4.1 Carbon Emissions Factor

To convert electricity output from the operational thermal plants into GHG emissions, it must be translated by the use of carbon emissions factor for each thermal plant. These factors depend on the technology used for the thermal transformation, its conversion efficiency and the characteristics of fuels utilized. Since all operational thermal power plant in Costa Rica are owned and operated by ICE, data output of these facilities are available in terms of power output, fuel consumption, efficiency, etc. Therefore, for each technology data is available. Calculations of these factors are presented in Table 8 below.

Table 9 – Fuel Consumption and Emissions Intensity of Existing and New Thermoelectric Plants

Fuel characteristic	Unit	Fuel oil	Diesel
Net calorific value	MJ/Kg	40.19	43.33
Density	Kg/l	0.96	0.855
Carbon content	KgC/GJ	21.1	20.2

Plant characteristic	KWh/l	l/KWh	Kg/KWh	MJ/KWh	Efficiency (%)	tonC/MWh	tonCO2/MWh
Existing 2001	*(a)*	*(b)*	*(c)*	*(d)*	*(e)*	*(f)*	*(g)*
Motor 2 (Fuel oil)							
Moin (14 MW)	4.2	0.24	0.23	9.19	39	0.19	0.71
Colima (26 MW)	3.5	0.29	0.27	11.02	33	0.23	0.85
Turbine 1 (Diesel)							
Moin (129 MW)	2.9	0.34	0.29	12.77	28	0.26	0.95
Turbine 2 (Diesel)							
Barranca (30 MW)	2.6	0.38	0.33	14.25	25	0.29	1.06
San Antonio (30 MW)	2.6	0.38	0.33	14.25	25	0.29	1.06
New Plants							
Turbine 1 (Diesel)							
Moin (72 MW)	2.9	0.34	0.29	12.77	28	0.26	0.95
Combined Cycle (Diesel)							
Barranca (120MW)	4.7	0.21	0.18	7.88	46	0.16	0.58
Motor 1 (Fuel oil)							
MSDM (20 MW)	4.6	0.22	0.21	8.39	43	0.18	0.65

b= 1/(a)
c = (b) x fuel density
d = (c) x net calorific value
e = (3.6 GJ/MWh/(d)) x 100
f =((d) x carbon content)/1000
g = (f) x (44/12)

5.4.2 Calculation of Baseline Emissions per Scenario

This Section presents the results of the emissions calculation for the baseline scenarios described in Section 5.2. For each scenario, the baseline electricity generation (per year), the related carbon emission factor and the total baseline emissions during the 10-year crediting period is given.

Assumptions made for calculating the carbon emission factor for each of the three baseline scenarios are:

- The system boundaries selected for the baseline scenario are the same as the system boundaries that have been defined for the project case;
- The baseline scenarios only take into account emissions directly related to the generation of electricity at the grid;

- The baseline parameters have been aggregated at national and sectoral level, based on characteristics and performance of the NIS. Furthermore, the ICE's generation expansion plan (2002-2016) was considered as indicative for accounting uncertainties related with demand growth, energy supply (e.g. new additions and decommissioning of old thermal power plants) and baseline emissions;
- The generation of electricity using fossil fuels generates CO_2, CH_4 and N_2O emissions. Taking other than CO_2 emissions into account will result in higher carbon emission factors expressed in CO_2 equivalent unit per unit of energy output, specially since global warming potential of these GHG are higher. The quantification of the emissions for the baseline scenarios does not take into account emissions of GHG other than CO_2. The scenarios presented are therefore more conservative than scenarios that would include CH_4 and N_2O emissions.

5.4.2.1 Continuation of the Current Situation – Scenario 1

The starting point of this baseline scenario has been determined by calculating the weighted-average carbon emission factor expressed in tones of carbon dioxide equivalent units per unit of power output of the current mix of operational thermal power plants connected to the NIS in the year 2001. Table 9 below summarizes the result.

This scenario assumes that the existing characteristics of the current operational thermal plants mix and its baseline related weighted-average emission factor would remain constant during the 10-year crediting period. The annual emissions for this baseline scenario will be calculated based on the following formula:

$$\textbf{\textit{Baseline Emissions}} = \sum (\mathbf{O_p}) * \mathbf{EF_f}$$

O_p - Thermal power plant output given in Table 8.
EF_f – Carbon Emissions Factor (weighted-average) given in Table 10 below.

Technology	Output %	Average EF (ton CO2/MWh	Weighted Av. Emission Factor (ton CO2/MWh)
Turbine 1	64	0.95	0.608
Turbine 2	7	1.06	0.074
Motor 2	16	0.71	0.114
Total	100		0.796

Table 10 - Electricity output (%) and weighted average Carbon Emission Factor (2001)

Results are shown in Table 11 below and in Graph 1.

Table 11 - Annual emissions for the Baseline Scenario 1 (Current Situation)

Year	(GWh)	Emissions (103 ton CO2)
2003	272	217
2004	398	317
2005	506	403
2006	741	590
2007	767	611
2008	915	728
2009	1,005	800
2010	901	717
2011	1,004	799
2012	327	260
2013	394	314
2014	829	660
Total	8059	6415

5.4.2.2 Scenario of future additions

Is the baseline scenario comprising emissions projected ex-ante using an average emissions factor related with the performance of future thermal power plants additions to the NIS during the 10- year crediting period. The baseline emission factor will be given by the average emission factor of future additions as shown in Table 11 below. These plants have to become operational after the decommissioning of the current operational thermal plants.

This scenario assumes that the characteristics of the expected thermal plant additions would apply during the 10-year crediting period. This will be a more conservative emission factor since new and more efficient technology is expected according with ICE's expansion plan.

In addition to role out the old, less efficient and more emissive thermal power plants currently in operation, this scenario also role out the Moín turbine gas (Turbine 1) that will start operation in 2002 and will remain operational during the 10-year crediting period. Therefore, it is not a realistic scenario despite conservative.

$$\textit{Baseline Emissions} = \sum O_p * EF_f$$

O_p **-** Thermal power plant output (yearly) given in Table 8.
EF_f – Carbon emissions factor (average) given in Table 12 below.

Table 12 –Average Emission Factor based on New Additions to the NIS

Technology	Year	Average EF (ton Co2/MWh)
New Additions: Combined Cycle Diesel	2005	0.58
MSDM Fuel Oil (Motor 1)	2011	0.65
Av. Emission Factor (ton CO_2/MWh		**0.61**

Results are shown in Table 13 below and in Graph 1.

Table 13 - Annual emissions for the Baseline Scenario 2 (Future Additions)

Year	(GWh)	Emissions (10^3 $tonCO_2$)
2003	272	166
2004	398	243
2005	506	309
2006	741	452
2007	767	468
2008	915	558
2009	1,005	613
2010	901	550
2011	1,004	612
2012	327	199
2013	394	240
2014	829	506
Total	8,059	4916

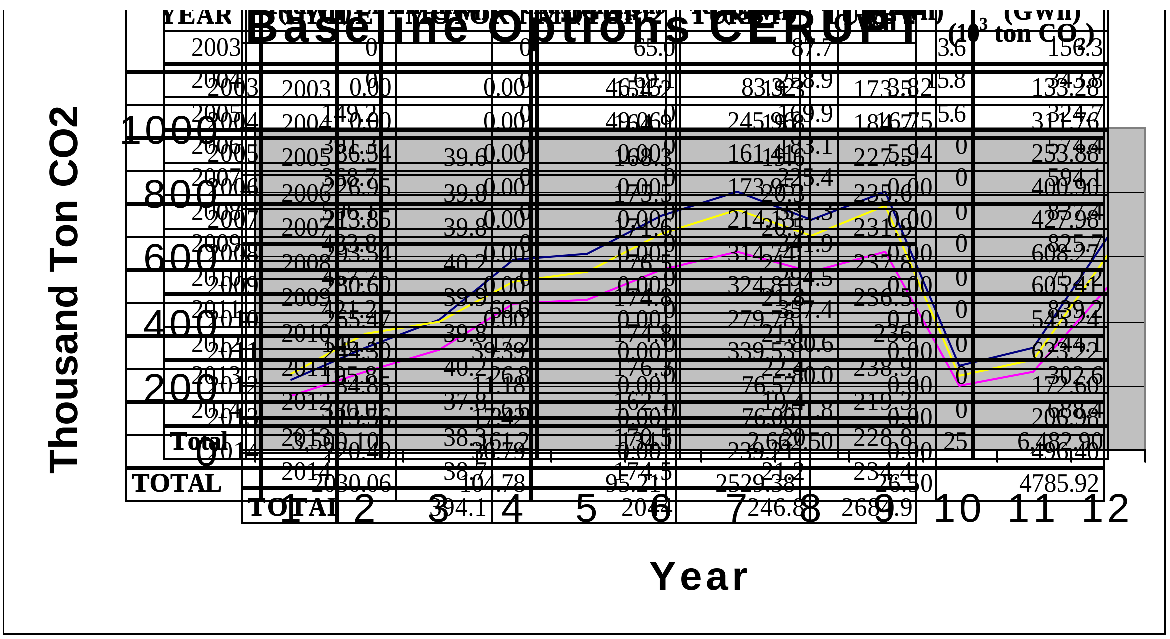
5.4.2.3 Scenario of current and future additions

Is the baseline scenario comprising ex-ante-projected emissions based on the performance of current and future thermal power plants additions to the NIS during the 10-year crediting period. The baseline emissions factor will be given by the weighted-average of current and future thermal power plants operation at the NIS as shown in Table 13 below. Under this scenario the baseline emissions will be based only on operational thermal plants. This is a realistic approach and the baseline scenario to be applied needs at least reflect this factor. Therefore, this scenario has been selected as most appropriate baseline for the CERUPT application. In addition, it reflects best how the electricity sector will evolve in the next 15 years according with the sectoral expansion plan.

$$\textbf{\textit{Baseline Emissions}} = \sum \mathbf{O_p} * \mathbf{EF_f}$$

$\mathbf{O_p}$ **-** Thermal power plant output (yearly) given in Table 8
$\mathbf{EF_f}$ – Carbon Emissions factor based on technology and fuel given in Table 9.

Results are shown in Table 14 below and in Graph 1.


Baseline Options CERUPT
Thousand Ton CO2
Year

7 CREDITING TIME

Start date of the project: 2003
Life time of the project: 40 year
Crediting time of the project: 10 year

8 ESTIMATION OF EMISSIONS REDUCTIONS

8.1 Emissions Reductions of CERUPT Projects

For calculating ERs attributable to the CERUPT group of project activities, it should be possible to determine *ex-ante* Emission Reduction Factors (ERFs) relative to the baseline's projected dispatch of the NIS. CERUPT projects ability to displace thermal generation was assessed through simulation of the NIS including the energy output of the three CERUPT projects (see Section 6.2.2) and results were compared with the simulation of the NIS under the baseline case (see Section 5.3.4). Differences will represent the CERUPT projects ability to displace thermal generation and its potential for production of ERs reasonably attributed to the CERUPT group of project activities. CO_2 emissions avoidance will be realized from the reduction of fossil fuel use in thermal power plants that otherwise would supply electricity in the baseline case.

Energy generated by the CERUPT projects would eventually replace thermal energy from various technologies. It would be difficult to identify which specific project replaced thermal energy from a specific plant at the NIS, or to assign priority for replacing thermal energy to a particular project. Therefore, it is reasonable to assume that the CERUPT projects will act as a block and thus the ERs they generate can be attributed to each of the projects in proportion to their energy output.

Ex-ante ERFs derived from this analysis, when applied to the generation of each CERUPT project during the 10-year crediting period, will result in creditable ERs. Same ERFs are applied to all CERUPT group of projects that are part of this application.

8.1.1 Thermal Generation Substitution

Calculation of the thermal energy substituted by the CERUPT group of projects was based on the difference between the simulation of the NIS under the baseline case (without project) shown in Table 7 and the simulation of the NIS including the CERUPT group of projects given in Table 16. The results are summarized in Table 18 below.

Potential substitution reaches a rather reasonable proportion of the energy available from the group of projects. Full substitution does not happen because during the off-peak hours of the wet season the renewable energy supply can surpass the off-peak demand and be at the margin at times (e.g. demand is less than 60% of the daily maximum). Therefore, the use of the model leads to a more conservative average ERs.

Table 18 – Thermal Generation Substitution under CERUPT group of projects Scenario

Year	Cyclo (GWh)	Motor 1 (GWh)	Motor 2 (GWh)	Turb 1 (GWh)	Turb 2 (GWh)	Total (GWh)
2003	0	0	33.3	76.5	6.2	116
2004	0	0	13.7	39.5	1.3	54.5
2005	83	0	0	91.9	7.2	182.1
2006	103.4	0	0	64	0	167.4
2007	111.1	0	0	62.5	0	173.6
2008	29.7	0	0	48.1	0	77.8
2009	79.4	0	0	100.7	0	180.1
2010	55.5	0	0	94.2	0	149.7
2011	54.6	10.3	0	100.7	0	165.6
2012	43.7	10.7	0	28.7	0	83.1
2013	27.7	5.5	0	58.3	0	91.5
2014	65.9	13.5	0	61.2	0	140.6
Total	654.00	40.00	47.00	826.30	14.70	1,582.00

8.1.2 Determination of *ex ante* Emission Reduction Factor

Energy substituted by the CERUPT projects given in Table 18 must be translated to ERs by the use of carbon emission factors for each of the displaced thermal plants given in Table 8. These factors depend on the technology used for the thermal transformation, its conversion efficiency and the characteristics of fuels utilized. The ex-ante estimated ERs in tons of CO_2 per year is summarized in Table 19 below.

Table 19 – Projected CERUPT Emissions Reductions at the NIS (10^3 ton CO_2)

YEAR	CYCLE	MOTOR 1	MOTOR 2	TURB 1	TURB 2	TOTAL (10^3 ton CO_2)
2003	0.00	0.00	23.64	72.68	6.57	102.89
2004	0.00	0.00	9.73	37.53	1.38	48.63
2005	48.14	0.00	0.00	87.31	7.63	143.08
2006	59.97	0.00	0.00	60.80	0.00	120.77
2007	64.44	0.00	0.00	59.38	0.00	123.81
2008	17.23	0.00	0.00	45.70	0.00	62.92
2009	46.05	0.00	0.00	95.67	0.00	141.72
2010	32.19	0.00	0.00	89.49	0.00	121.68
2011	31.67	6.70	0.00	95.67	0.00	134.03
2012	25.35	6.96	0.00	27.27	0.00	59.57
2013	16.07	3.58	0.00	55.39	0.00	75.03
2014	38.22	8.78	0.00	58.14	0.00	105.14
TOTAL	379.32	26.00	33.37	784.99	15.58	1239.26

The *ex-ante* ERFs, for a given year, applicable to the CERUPT group of projects can then be calculated as the ratio between the total CO_2 ERs for that particular year and the energy generated by the group of projects for that particular year. The result of this exercise provides the ERFs (tons CO_2/MWh) for each year within the period 2003-2014. As explained, the calculation of the ERF is conservative in the sense that, to avoid any possible overestimation of the ERs, the ERF are calculated assuming all the projects are competing for ERs. The resulting ERFs are summarized in Table 20 below. ERFs thus represent conservative values that, when applied to actual generation of the CERUPT group of projects, would ensure that ERs are duly credited without causing any overestimation.

Table 20 – Projected Yearly Emissions Reduction Factors (ERF) at the NIS

Year	El Encanto	Peñas Blancas	Rio Azul	TOTAL GWh	TOTAL (10^3 ton CO_2)	ERF (tonCO2/MWh)
2003		154.2	19.3	173.5	102.89	**0.59**
2004		164.9	19.8	184.7	48.63	**0.26**
2005	39.6	168.3	19.6	227.5	143.08	**0.63**
2006	39.8	175.5	20.3	235.6	120.77	**0.51**
2007	39.8	171.6	20.5	231.9	123.81	**0.53**
2008	40.2	176.5	21.1	237.8	62.92	**0.26**
2009	39.9	174.8	21.8	236.5	141.72	**0.60**
2010	39.8	174.8	21.4	236	121.68	**0.52**
2011	40.2	176.3	22.4	238.9	134.03	**0.56**
2012	37.8	162.1	19.4	219.3	59.57	**0.27**
2013	38.3	170.5	20	228.8	75.03	**0.33**
2014	38.7	174.5	21.2	234.4	105.14	**0.45**
TOTAL	**394.1**	**2044**	**246.8**	**2684.9**	**1239.27**	**0.46**

8.2 Emission Reductions for CERUPT Projects

Using the *ex ante* ERFs given in Table 20 above and assumptions about the energy provided to the grid by the three CERUPT projects given in Table 15, the expected ERs for each project can be projected for the 10-year crediting period. The yearly ERs for the CERUPT group of projects is summarized in Table 21 below.

Table 21 – Projected Emissions Reductions for CERUPT group of projects during 10-year crediting period

Year	El Encanto	Peñas Blancas	Rio Azul	TOTAL (10^3 ton CO_2)
2003		91.44	11.45	102.89
2004		43.42	5.21	48.63
2005	24.91	105.85	12.33	143.08
2006	20.40	89.96	10.41	120.77
2007	21.25	91.62	10.94	123.81
2008	10.64	46.70	5.58	62.92
2009	23.91	104.75	13.06	141.72
2010	20.52	90.13	11.03	121.68
2011	22.55	98.91	12.57	134.03
2012	10.27	44.03	5.27	59.57
2013	12.56			12.56
2014	17.36			17.36

Given the commissioning dates provided by project sponsors, total ERs for a 10-year crediting period (2003 – 2014) for the CERUPT projects is calculated at about 940,990 ton CO_2. For the specific case of the Peñas Blancas Hydroelectric project the total ER is calculated at about 806,800 ton CO_2 during the 10-year crediting period (2003-2012).

8.3 Changes to the Emissions Baseline over Time and Renewal of ERFs

It is possible that the basis for the calculation of *ex ante* ERFs changes over time, for instance when SIEPAC comes on line. The concept of *ex ante* fixed ERFs implies a reasonable attempt to anticipate possible changes in the emissions baseline, in particular changes in the dispatch behavior and the expansion plan. However, changes, such as the arrival of SIEPAC, cannot be excluded, but their timing is often not known.

The SIEPAC is expected to develop a regional bulk supply under a competitive market. It will bring opportunities and threats to the NIS. It will enhance exporting firm renewable power to any part of the Isthmus. On the other hand, under a competitive market and favourable prices of fossil fuels, it could enhance importing thermal power from regional generators without aggregate value to our economy.

Under SIEPAC scenario export of electricity by Costa Rica could theoretically lead to an increase of emissions reductions. This would happen since the ERF used to calculate ERs at the NIS is much lower than the ERF of the energy displaced outside of Costa Rica since thermal penetration outside Costa Rica is much higher. Furthermore, Costa Rica exports only hydropower surplus and only after it has satisfied its own demand. Under this situation the ERF at the NIS is (near) zero despite it is reasonable to assume that the energy exported by Costa Rica replaces thermal energy from units of size and efficiency similar to those existing in Costa Rica.

Though the overall conceptual design of SIEPAC is well defined, the institutional and regulatory systems that prevail in some of the partner countries are not compatible with the establishment of a regional market. It is unlikely that major reforms will be introduced soon in the countries that have not yet reformed their power sectors. Therefore, Central American community is searching for options that would permit further progress of SIEPAC within the limitations of the current institutional arrangements.

On this matter ICE has taken a conservative approach and has delayed the consideration of regional exchanges in its development plans until plans for implementing SIEPAC have been firmer and better established. Project developers estimate 2006 as the earliest date when SIEPAC could become operational. Some experts consider it unlikely that the interconnection would be built in this time frame.

In virtue of the above, the determination and fixing of *ex ante* ERFs for a 10-year crediting period seems reasonable and conservative.

9. MONITORING PROTOCOL

9.1 Purpose

In the context of the CDM, monitoring describes the systematic surveillance of a project's performance by measuring and recording performance-related indicators relevant to the project activity. Verification is the periodic auditing of monitoring results, the assessment of achieved ERs and of the project's continued conformance with all relevant project criteria.

This Monitoring Protocol (MP) describes the requirements for the collection and processing of data from the CERUPT group of projects for the purpose of calculating and verifying the ERs reasonably attributed to their project activities. Is a working document that identifies key performance indicators and sets out the procedures for tracking, monitoring, calculating and verifying the impacts of project activities.

This MP must be used for the planning and implementation of the project and during its operation. Adherence to the instructions in the MP is necessary to successfully measure and track the project's impacts and prepare for the periodic verification process that will have to be undertaken to confirm the ERs achieved by the project. The MP is thus the basis for the production and delivery of ERs to SENTER Internationaal or other buyers and for any related revenue stream.

The MP contains the requirements and instructions for:

- establishing and maintaining the appropriate monitoring system for the calculation of ERs;
- implementing the necessary measurement and management operations;
- preparing for independent, third party verification of ERs.

The MVP must be:

- adopted as key input into the detailed planning of the project, and
- included into the operational manuals of the project.

The data monitored as per this MP are in line with the kind of information routinely collected by an electric power generator. The MP can be updated and adjusted to meet operational requirements, provided the Verifier during the process of initial verification approves such modifications.

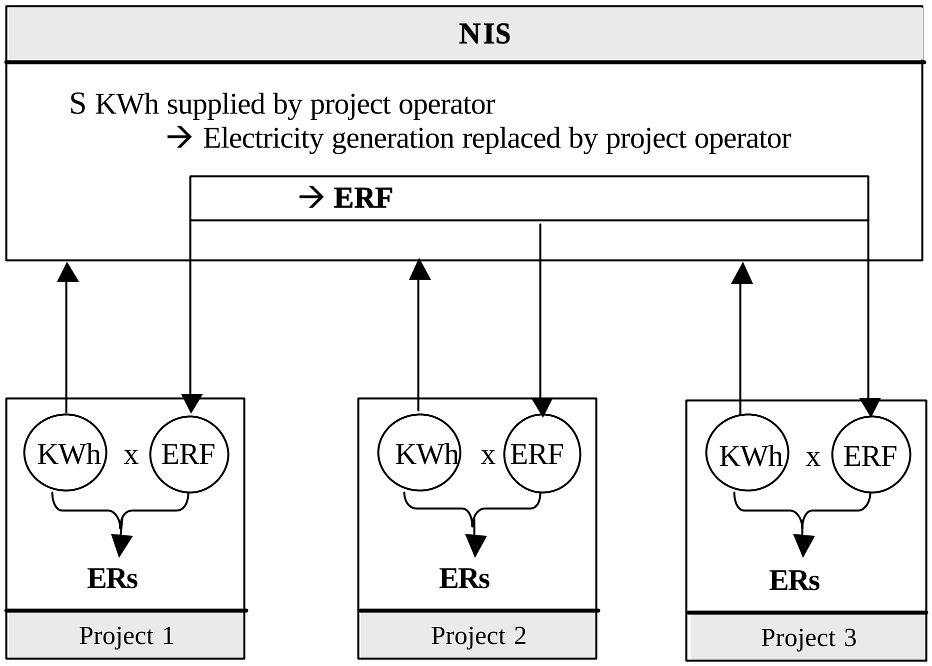
9.2 Monitoring Assumptions

The MP builds on the sectoral baseline study determined for the CERUPT projects. It includes *ex ante* determined ERFs values for the period 2003 through 2012. These factors are confirmed by validation. The ERFs are taken from Table 20.

9.3 Electric Supply

For each year, the SP operator measures and records the electric power (in GWh) that the project supplies to ICE or to some other buyer who would otherwise buy power from ICE. To calculate the ERs for this year the operator must multiply the lower of either the metered generation or the project expected generation figure for this year given in Table 15 with the ERF for this same year given in Table 20.

Monitoring and ER Calculation for the CERUPT projects



9.4 Monitoring Obligations and Calculation of ERs

The project operator must fulfill the following operational and data collection obligations in order to maximize the ERs achieved by the project and to ensure that sufficient information is available to calculate ERs in a transparent manner and to allow for a successful verification of these ERs.

Metering of Electricity Supplied

The project operator must install an electric meter at the substation where the electricity generated by the project is feed into the national grid or sold to a buyer that would otherwise purchase power from ICE. Metering at the substation will exclude any parasitic loads. The project operator will install the electric meter in such a way that only electricity produced by the project as described in the relevant project documents will be metered: electricity not produced by the project must be excluded. Data obtained for the purpose of calculating ERs must be consistent with the data used for billing purposes.

Existing commercial meters can be used provided these are:

- certified electronic meters of precision class 0.2%, placed at the SP's substation at the delivery point (downstream from any own consumption);
- able to integrate the instantaneous sum of the power of the whole plant;
- able to record electricity supplied to the grid (in GWh) on a daily or at least monthly basis.

The project operator must read the meter and record the metered data at appropriate intervals, but at least at the end of each month. The meter should be able to record daily data, ideally in electronic form that can be automatically processed and reported.

Recording of Electricity Supplied and Calculation of ERs

This MP provides a workbook that can be used to record monthly generation data and calculate monthly ERs. The project operator may use this workbook or will develop or obtain an equivalent tool for automatic recording, reporting and calculation of ERs. The tool should be integrated with the metering and reporting system.

The workbook contains the following fields:

Project Name, Year: To be completed when a new worksheet is started.

Emission Reduction Factor (ERF): Records the ERFs (in tons of CO2 per GWh) as include in Baseline Study.
Energy Output: Records of the electricity output in GWh/year as reported by the project operator
Metered Electricity Supply: Records monthly net electricity (in GWh) supplied by the project as measured and reported by the operator.
Emission Reductions: Calculates the ERs (tons of CO_2) achieved yearly by the project.
Signature and Date: These fields are to be completed after every entry into the worksheet.

Table 22 – Monthly Power Supplied and yearly ERs for the CERUPT Project

Project Name:						
Year:			Months			Year
	Unit	Equation	1	…	12	Sum
Emission Reduction Factor	t CO2 / GWh	A				--
Expected Output	GWh/month	B				
Metered Energy Supply	GWh/month	C				
Creditable Energy	GWh/month	D: = C if C > B D: = C if C ≤ B				
Emission Reductions	1,000 ton CO_2	E = (A * D)				
Signature / date	-	-				

The project operator must complete the worksheet depicted in Table 22. Each workbook must be saved with a unique name reflecting the year for which monitoring has been carried out. Paper or electronic records such as meter output and monthly energy billings must be kept available for inspection; the monthly recording must tally with the monthly billings.

The monthly workbooks together with the project database and monitoring record form the “paper trail”, which is essential for verification. These yearly workbooks will be a transparent record of electricity supplied and ERs.

9.5 Operational System

In order to ensure the credibility and verifiability of the ERs achieved, the project must have a well-defined operational system. It is the obligation of the project operator to put such a system in place. The system must include the operation of monitoring and record keeping as described in this MP. The proper functioning of the operational system must be monitored by the project operator and will be subject to third party verification.
This includes:

Data handling:

- The establishment of a transparent system for the collection, computation and storage of data, including adequate record keeping and data monitoring systems is required. The system should allow automated recording and reporting of data. The project operator must develop and implement a protocol that provides for the above functions and processes, which must be suitable for independent auditing.
- For electronic and paper based data entry and record keeping systems, there must be clarity in terms of the procedures and protocols for collection and entry of data, use of workbooks and spreadsheets and any assumptions made, so that compliance with requirements can be assessed by a third party. Stand-by processes and systems, e.g. paper based systems, must be outlined and used in the event of, and to provide for, the possibility of system failures. The record keeping system must provide a paper trail that can be audited.

Reporting:

- Project operator will also report to the SENTER International as per the ERs Purchase Contract with SENTER.
- The project operator must prepare reports as needed for verification purposes.

Training:

- The project operator will ensure that the required capacity is made available to its operational staff to enable them to undertake the tasks required by this MP.

Preparation for operation:

- The management and operational system and the capacity to implement this MVP must be put in place before the project can start generating ERs.

Table 23 below summarizes the roles and responsibilities of the project partners with regard to the monitoring system for the SP.

Table 23 – MP Operation System

Task	Project Operator
Monitoring system	Review MP and suggest adjustments if necessary Develop and establish operation system Establish and maintain monitoring and reporting system and implement MP Prepare for verification

Task	Project Operator
Data Collection	Establish and maintain data measurement, collection and record keeping systems for power supply Check data quality, collection and record keeping procedures regularly
Data computation	Complete MP workbook Or develop and use equivalent recording, calculation and reporting tool for ERs
Data storage systems	Implement record maintenance system Store and maintain records (paper trail) Implement sign-off system for records and completed worksheets
Monitoring and reporting	Analyze data and compare project performance with project targets Prepare and forward annual report and worksheets to SENTER Internationaal
MP capacity building	Develop and establish MP skills review and feedback system Ensure that operational staff is enabled to meet the needs of this MP
Quality assurance, audit and verification	Establish and maintain quality assurance system with a view to ensuring transparency and allowing for verification Prepare for, facilitate and co-ordinate audits and verification process