CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 02 - in effect as of: 1 July 2004)

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

Poechos I ("The Project")

A.2. Description of the project activity:

The Project is a hydroelectric power plant located in Peru, in the North-western Department of Piura. The Project's installed capacity and projected yearly average generation is 15.2 MW and 57,740 MWh per year, respectively. The expected load factor is 43.36%. The Project is expected to displace 31,463 tCO_2e per year, which accounts for 220,241 tCO_2e for the first crediting period (7 years), generating the equivalent amount of Certified Emission Reductions (CERs). Methane and Carbon Dioxide are negligible. Therefore, there is no need to monitor leakage and it will not be taken into account when calculating ERs.

The Project takes advantage of the existing Poechos reservoir of 48 m height and approximately 1,000 m length (with a water discharge of 45 m^3/s), constructed between 1971 and 1974, exclusively for the irrigation system named Chira-Piura[1]. The machine house was built downstream at the bottom gate of the dam. The Project uses a portion of the discharged water from the Poechos Dam, affecting the flow of the Chira River and the Miguel Checa Canal. The water concession granted to the sponsors by the Peruvian Department of Agriculture was based upon the use of the flow required for agriculture – so that generation received lower priority than agricultural needs. Although the reservoir allows for a multi-year regulation of the water, The Project will not have facilities to regulate its energy production because the control of the discharges is managed by the Agricultural Authority of the region.

The spatial extent of The Project boundary is the National Electric Grid (*SEIN*). The Project is connected to the *SEIN* through the Sullana Substation - which belongs to Electronoroeste S.A. (ENOSA). The expected 57,740 MWh of electricity generated per year will be sold to ENOSA (stated-owned enterprise) – a PPA is currently signed between SINERSA (The Project Operator and Sponsor) and ENOSA. The Project will have an expected minimum plant operating life of 40 years.

A.3. Project participants:

-SINERSA. SINERSA is The Project Sponsor. SINERSA is a Peruvian private company solely developer, operator and shareholder of The Project. It holds the definitive concession right to build and to operate the hydropower plant of Poechos I (The Project) acquired from The Peruvian Department of Energy and Mines ("*MINEM*").

-The Netherlands Clean Development Mechanism Facility ("the NCDMF"). The International Bank for Reconstruction and Development (World Bank) is the Trustee of the NCDMF and purchases certified emissions reductions on the behalf of the Government of the Netherlands.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

Department of Piura, Peru

[1] The Chira-Piura dam is the largest in Peru.

A.4.1.1. Host Party(ies):

Republic of Peru

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

Department of Piura (Piura Region) / Sullana Province / Lancones District.

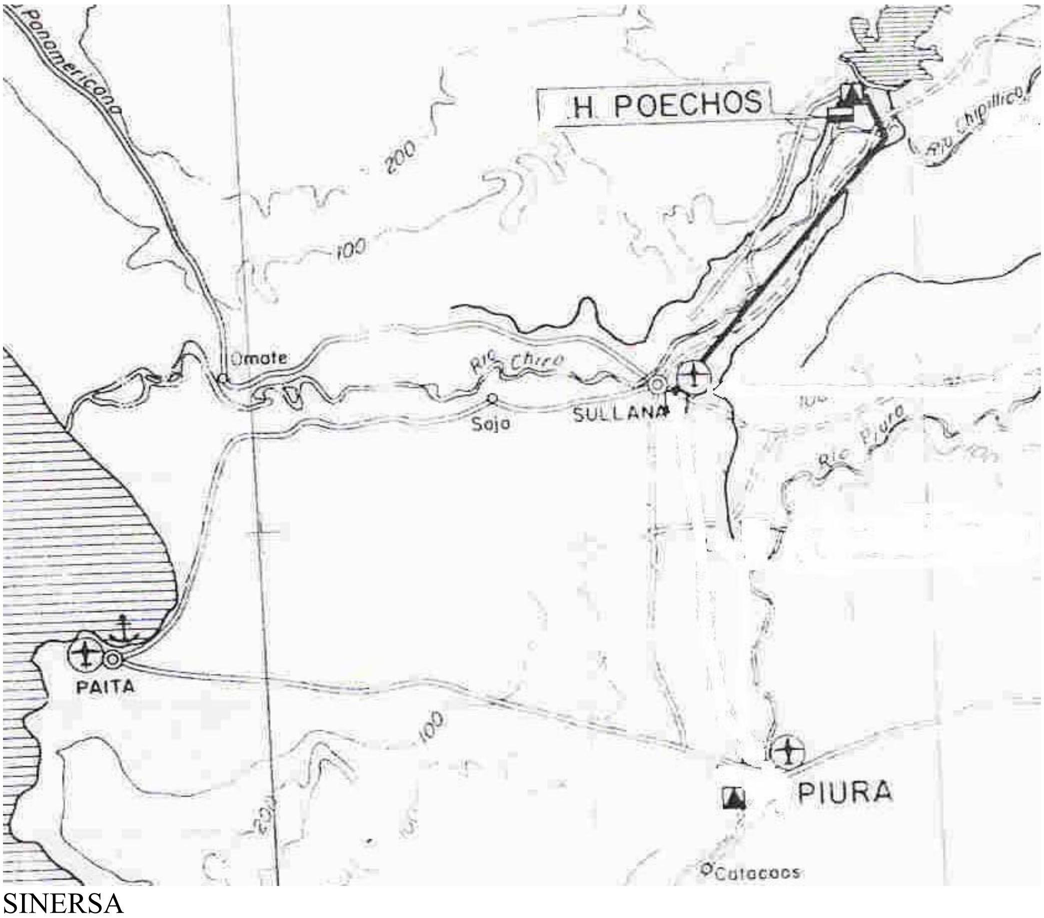
A.4.1.3. City/Town/Community etc:

Lancones Town (capital of the Lancones District)

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

The Project is located in the North-western Peruvian Department of Piura, in the Sullana Province, in the Lancones District, in the Lancones Town. The Project site is 40 Km from the Sullana district (capital of the Sullana Province), and 30 km from the Peruvian-Ecuadorian border. The plant is located within the property of the Poechos dam, built over the Chira River[2].

The Project Site Map



Source: SINERSA

[2] In 1974, with the solely purpose to provide irrigation for 110,000 has. in the Chira and Piura valleys.

***SEIN* Map**

N° 1

FUENTE : MEM - DGE
Actualización : COES SINAC 2003

Source: Own production with MAP taken from 2003 COES Statistics.

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

The Project falls into:
Sectoral Scope Number: 1
Sectoral Scope: Renewable Energy
Project Activity: Grid-connected renewable power generation; electricity capacity addition from a hydro power project with existing reservoir where the volume of the reservoir is not increased.

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

The technology employed is based on conventional Kaplan turbines (2) and generators (2) that are widely used all over the world.

The penstock of the powerhouse is connected to the existing steel pipe of the bottom outlet. The penstock is bifurcated in two penstock pipes leading to a powerhouse with two generating units each of 7.6 MW capacity. The generating units consist of two Kaplan turbines coupled to synchronous generators (3-phase) each of 9.5 MVA nominal capacity. That part of the powerhouse in which the main equipment is installed is an underground reinforced concrete structure, whereas the other part is an above ground steel structure. The water is discharged into a tailrace channel (capacity 45 m^3/s) connected to the existing energy dissipater (stilling basin) of the bottom outlet and, hence, is fed back into the irrigation system. The control building is installed adjacent to the powerhouse. This building contains the control room, offices and auxiliary installations. The control room is equipped with a modern system for automatic and remote control (SCADA).

The project does also contain a 60 kV open-air switchyard with one main transformer of 29 MVA capacity. The power plant will be connected to the national grid through a new 60 kV overhead transmission line. The transmission line has a length of 38-km and will be connected to the existing Sullana substation.

A.4.4. Brief explanation of how the anthropogenic emissions of anthropogenic greenhouse gas (GHGs) by sources are to be reduced by the proposed CDM project activity, including why the emission reductions would not occur in the absence of the proposed project activity, taking into account national and/or sectoral policies and circumstances:

The Project will generate electricity without emitting GHG. It will reduce anthropogenic GHG emissions by displacing GHG that are emitted when burning fossil fuels to generate power. The Project is projected to reduce 31,463 tCO_2e annually[3], generating an expected total of just over 220,241 tCO_2e for the duration of the initial 7-year crediting period.

The ERs are not likely in the absence of The Project activity, because national policies are currently fostering the development of the Camisea natural gas deposits and of gas exploration (i.e. to be used by The Camisea LNG Project) with special emphasis on promoting electricity generation based on natural gas.

Since 1998, the successive Peruvian governments have adopted a clear positive position regarding the promotion of the Camisea project and of changing the electricity generation matrix composition in favor of gas, this position have been reinforced along time, after seeing the successes in the different

[3] ER estimates are based on the “Consolidated Baseline Methodology for grid-connected electricity generation from renewable sources” (ACM0002).

developmental phases of the Camisea project, in operation from August 2004. First of all, pro-Camisea political decisions were based on governmental interest. The Peruvian Government had been interested in developing Camisea because it would reduce the current deficit in Peru's hydrocarbons trade balance by substituting imports, mainly of diesel and LPG, and by allowing exports (Naphtha, LPG surpluses); it would bring large foreign investment inflows (i.e. Camisea LNG Project), it would foster the development of a gas-based petrochemical industry; these altogether with new employment opportunities. Second of all, the political decisions taken made sure to create the necessary incentives to align the private interest with the public interests in Camisea, and this is what has allowed ultimately the Camisea project fast progress. In several opportunities these governmental interventions had gone explicitly against hydro-development as it constituted the first competitor of gas in terms of variables costs. Some of this laws involved:

-September 27, 1998: Law 26980 – Law that modified several articles and definitions annexed to ECL. On its third Transitory Disposition mandated the suspension for 9 months in the presentation of petitions for temporal and definite concessions in hydropower plants

-June 4, 1999: Law 27133 – Law of Promotion of the Natural Gas Industry – On its Unique Complementary Disposition extended the suspension of hydropower plants for 12 additional months from June 1999

-December 22, 1999: Law 27239 – Law that modified several articles of the ECL- On its Unique Complementary Disposition mandated that priorities to admit new temporal and definitive concession in hydropower plants would be determined as a function of the national development.

Lastly, the government, as of today, is still creating incentives to reinforce sustainability of the Camisea Project and of the prospects of the Gas industry in Peru, in order not to avoid any turnarounds in the advancements. Some of the most recent Laws given in favor to natural-gas-based electricity generation are:

-June 25, 2004: DS 019-2004 – Supreme Decree that promotes electricity generation based on natural gas – On its Article 1 indicates that for the next 2 years from June 25 2004, the guarantee required by article 66 of the ECL Rules will be reduced to 0.25% (before 1%) of total project budget with a ceiling of 200 UIT[4](before 500 UIT), when the petition for Authorization is for natural gas-based thermal generation

-August 5, 2004: DS 107-2004-EF- Clarifies that natural gas on its gassy-state will not be comprised in the New Appendix III , which attains Selective Consumption Tax (ISC) affection only, of the TUO[5] of the VAT and ISC Law – Indicates that natural gas on its gassy-state will not be affected by ISC.

-November 24, 2004: DS 041-2004-EM – Supreme Decree that promotes the installation of Thermal Plants that use natural gas as fuel - This law is specifically oriented to promote that other-fossil fuels generating plants be modified in their installations to function with natural gas. This law grants the same benefit specified in DS 019-2004 but for the new gas-fired power plants to be developed by owners that get to modify their other-fossil-fuel fired thermal plants' installations to function with natural gas.

[4] *Unidad Impositiva Tributaria.*
[5] *Texto Unico Ordenado.*

In conclusion, as of today, all information available indicates that emission reductions will not occur in the absence of the proposed Project Activity because of all three: National policies, sectoral policies and the Camisea particular circumstance that foster thermal technology against hydro-developments.

A.4.4.1. Estimated amount of emission reductions over the chosen crediting period:

The Project is estimated to reduce 31,463 tCO_2e annually, generating an expected total of just over 220,241 tCO_2e for the duration of the initial 7-year crediting period; 660,723 tCO_2e over the 21-year period.

A.4.5. Public funding of the project activity:

The Project has not received any type of public funding or public financial help.

SECTION B. Application of a baseline methodology

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

Approved consolidated baseline methodology ACM0002: Consolidated baseline methodology for grid-connected electricity generation from renewable sources ("The Methodology")

The Methodology will be used in conjunction with the approved monitoring methodology ACM0002 ("The Monitoring Methodology")

B.1.1. Justification of the choice of the methodology and why it is applicable to the project activity:

The Project is a grid-connected zero-emission renewable power generation activity and meets all the conditions stated in The Methodology (ACM0002). These conditions are:

- The Project supplies electricity capacity addition (15.2 MW) from a hydropower source; it is a hydro-power plant with existing reservoir where the volume of the reservoir is not increased
- The Project is not an activity that involves switching from fossil fuels to renewable energy at The Project site
- The electricity grid (the *SEIN*) is clearly identified and information on the characteristics of this grid is available.

B.2. Description of how the methodology is applied in the context of the project activity:

The baseline scenario is electricity that would have been otherwise generated by the operation of grid-connected power plants and by the addition of new generating sources. Following The Methodology, the baseline emission factor is calculated as a combined margin (CM), consisting of the simple average of the operating margin emission factor (OM) and the build margin emission factor (BM). All margins are expressed in tCO_2e/MWh.

CM= 0.5*OM + 0.5*BM

According to The Methodology, the combined margin is deemed to represent the tCO_2e/MWh that would have been emitted in the absence of The Project. Emissions reductions will be claimed based on the total CO_2e emissions mitigated by The Project. The Project Boundary considered is The *SEIN*. No leakages or indirect emissions were identified for The Project.

The Following four steps have to be made in order to calculate The Project' CERs:

Step 1: Calculation of the Operating Margin emission factor
The OM selected in the BLS was the Dispatch Data Analysis Operating Margin Emission Factor because The Methodology specifies that: The c) Dispatch Data Analysis OM be the first methodological choice where the required data is available. **The DDA-OM selection for the OM should hold for the first crediting period of The Project.**

The DDA-OM is calculated as: E_OMy/EGy
E_OMy = Sum of [average tCO_2e/MWh emitted by plants that fall within the top 10% of grid dispatch each hour of the year "times" The Project generation in MWh each hour of the year]
And,
EGy = The Project generation in the year in which actual project generation occurs. For The Project "the year" would run from April 1st to March 31st, being the first year of the first crediting period April 2004-March 2005 and the last year of the first crediting period April 2010-March 2011.

Following the Methodology, the BLS's resulting Dispatch Data Analysis Operating Margin Emission Factor (DDA-OM) was **0.72614 tCO_2e/MWh** and it was obtained from dividing E_OMy by EGy, as explained above[6].

Step 2: Calculation of the Build Margin (BM) emission factor[7]
The BM emission factor is defined in The Methodology as the generation-weighted average emission factor (tCO_2e/MWh) of a sample of power plants. Such sample should be composed by either the 5 most recently built plants or the plants whose aggregated generation comprises the most recent 20% of *SEIN* generation in the year of project generation occurrence[8], whichever group's generation is greater – both list should exclude CDM-Status Plants[9]. The Methodology, gives 2 options for the calculation of the BM. **The second option was selected (BM2) in the BLS** for the sake of conservativeness – this option does not include in-construction plants in the sample and must be updated annually ex-post for all crediting periods**. The second option for the BM should hold for the first crediting period of The Project.**

The Formula to apply to the selected sample is:
EF_BMy (tCO_2e/MWh) = [∑I,m Fi,m,y,*COEFi,m] / [∑mGENm,y];
m = plants of the selected sample, F = their generation in MWh, COEF = their tCO_2e/MWh factor, GEN= total sample generation.

As done in the BLS, in the monitoring of The Project's CERs, the plants capacity additions to consider in the BM should be obtained by comparing annual statistics of installed capacity in the *SEIN* across latest years, and by selecting from these additions identified, only the ones that represent new units added or no more than 5-year old plants interconnected to the *SEIN* ("Newly Built") – this criteria was established in the BLS for the sake of conservativeness. The additions in the SEIN that should be discarded for the BM correspond to interconnection of older units, rehabilitation of plants, and/or upgrades

"Newly Built" capacity additions from 1988-2003[10] can be seen in E.4

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[6] See more in detail explanation in E.4.
[7] Source Data for the BM calculation is in Annex 3: Installed Capacity per power plant of the *SEIN* as of December 31st at years 1996 to 2003. and *SEIN* Installed Capacity Additions from 1998 to 2003 (all categories).
[8] In the BLS, the 3 most recent years' annual average generation of the new units added to the *SEIN* was taken because The Project had not generated electricity for an entire year yet.
[9] As of today, The Project is the only CDM-Status Plant in Peru (*SEIN*).
[10] The entire list of capacity additions in the *SEIN* (al l sorts) from 1988 to 2003, and can be seen in Annex 3.

Out of identified "Newly Built" capacity additions in the *SEIN*, the 5 most recent plants/units built were: 1)Yarinacocha(2003), 2)Huanchor(2002), 3)Tumbes(2001), 4)Yanango(2000) and 5) Chimay(2000), whose comprised annual generation was 1,300.5 GWh.
Identified "Newly Built" capacity additions in the *SEIN* built since year 1993 up to 2003 composed the 20% most recently built plants in generation; these plants comprised annual generation was 3,860.08 GWh. Hence, the latter group was selected in the BLS because its comprised generation was greater. In the monitoring this comparison between both samples should be made annually ex-post.

The BM2 is calculated as the average tCO_2e emitted by the selected sample. Following the Methodology, the BLS's resulting Build Margin Emission Factor was = **0.36371 tCO_2e/MWh**[11].

Step 3: Calculation of the Baseline emission factor
Following The Methodology, The BM emission factor is the CM calculated as the weighted average of the OM and the BM- default weights of 50%, 50% were kept. In the BLS, this calculation was as follow:

CM= 0.5*OM+ 0.5*BM
CM= 0.5*(0.72614) + 0.5*(0.36371) = **0.54493 tCO_2e/MWh**

Step 4: Calculation of The Project's Emissions Reductions Prior to Validation
Because The Project itself does not produce any emission, no leakages enter into the calculation of estimated ERs, and the baseline emissions are estimated to be equal to The Project ERs

The estimated ERs per year for The Project are obtained from the following multiplication:
Estimated Baseline Emissions = CM* (Estimated Annual Project Generation in MWh)
Estimated ERs per year = CM* (Estimated Annual Project Generation in MWh)
Estimated ERs per year = 0.54493 tCO_2eMWh * 57,740 MWh = 31,463 tCO_2e or 31,463 ERs

The ERs per year estimated for the first crediting period are:
Estimated ERs for the first crediting period = 31,463 tCO_2e/yr* 7 yrs = 220,241 tCO_2e or Estimated ERs[12].

B.3. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity:

The following steps from the "Tools for the demonstration and assessment of additionality" (EB16 Report) will be completed in this section:

Step 0: Preliminary screening based on the starting date of the project activity
Step 1: Identification of alternatives to the project activity consistent with current laws and regulations
Step 2: Investment analysis to determine that the proposed activity is not the most economically or financially attractive;
Step 3: Barriers analysis
Step 4: Common practice analysis
Step 5: Impact of registration of the proposed activity as a CDM project activity
Based on information about activities similar to the proposed activity, the common practice analysis is to complement and reinforce the investment and barrier analysis.

[11] See more in detail explanation in E.4.
[12] All margins were rounded to the fifth decimal, but the CERs per year was rounded down to the nearest integer. The exact generation herewith considered is 57,739.5 MWh/yr, this generation does not need to be rounded down to the nearest integer.

Step 0 - Preliminary screening based on the starting date of the project activity:
During 2001, the World Bank and the Government of Peru undertook a National Strategy Study (NSS) with the purpose of positioning the country towards the new CDM market. Part of the study aimed at identifying possible CDM projects in Peru. Finanzas Ambientales, a local CDM consultancy on its capacity of NSS consultants identified Poechos I (The Project) as a possible CDM candidate. The Project sponsors retained Finanzas Ambientales as their own advisor for the CDM component of The Project, and a preliminary PDD was elaborated in February 2002 showing the sponsors' early determination in including Carbon Finance as an integral part of their project's design. Documented proof of these facts is made available to the DOE. The loan agreement to fund The Project was signed in October 2002 fully integrating Carbon Finance cash flows in the financial models. **Construction started in November 2002.**

Project participants do wish to have the crediting period starting prior to the registration of The Project activity.

The plant was commissioned in April 2004. The Project has been ready for CDM Registration since May 2003, but project sponsors chose to wait until a grid-connected electricity methodology was formally approved.

For all of above, The Project is eligible for attaining a crediting period starting in April 1st, 2004 before its date of registration.

Step 1 - Identification of alternatives to the project activity consistent with current laws and regulations
Sub-step 1a. Define alternatives to the project activity:
The identified realistic and credible alternatives available to The Project participants that **provide outputs or services comparable** with the proposed CDM project activity are three:

1) Implement The Project as a hydropower plant development **without** CDM assistance

2) Implement The Project as a natural gas power plant

3) Do not implement any power generation project

Sub-step 1b. Enforcement of applicable laws and regulations:
The identified alternatives are in compliance with all applicable legal and regulatory requirements. The 3 identified alternatives comply with Peru's ECL (Law 25844) released in 1993. Some relevant Articles of Peru's ECL that indicate that the alternatives are a plausible possibility for the project participants are: a) From Article 1- electricity generating activities can be developed by natural or juridical persons, whether they are national or foreigners. The juridical persons (private companies) should be incorporated under Peruvian laws; b) From Article 3 - A Concession is required for the development of hydro power plants (or geothermic plants[13]) if their installed capacity is greater than 10 MW, c) From Article 4 – An Authorization is required to develop fossil-fuel thermal plants if their installed capacity is greater than 500 KW, and hydropower plants and geothermic plants if their installed capacity is less than or equal to 10 MW, d) From Article 6 – The Concessions and Authorizations can be granted by the *MINEM*, who would establish for that a Registration of the Electric Concessions. e) From Article 7 – electricity generating activities that do not required Concession or Authorization could be developed freely upon compliance with technical norms and dispositions of environmental conservation and Cultural Patrimony conservation - the owner of the title of these activities should inform the *MINEM* the initiation of

[13] As of today, inexistent in Peru.

activities and the technical characteristics of the project and installations. F) From Article 9 – The Peruvian Government preserve the environmental conservation and the Cultural Patrimony of the Nation, as well as the rational use of the natural resources in the development of activities related to generation, transmission and distribution of electricity.

Because none of the identified alternatives breaks any legal or regulatory requirement, including the fact that none of the three are posed to go against technical norms and dispositions of environmental conservation and Cultural Patrimony conservation, all 3 scenarios are in compliance with all applicable laws and regulations and are also realistic and credible alternatives available to the project participants - Meaning The Project is additional under Step 1.

Step 2 – Investment Analysis to determine that the proposed activity is not the most economically or financially attractive:
To conduct the investment analysis the following four sub-steps were taken:

Sub-step 2a. Determine an appropriate analysis method
The CDM project activity generates financial and economic benefits other than CDM related income, therefore the Cost Analysis (Option I) cannot be taken. Out of the comparison analysis (option II) and the benchmark analysis (Option III), the benchmark analysis (Option III) was chosen.

Sub-step 2b - Option III. Apply the benchmark analysis
The identified financial indicator is: **Unit cost of service ($/MWh)**
The indicator for The Project is: **Levelized cost of electricity production ($/MWh**)
The relevant **benchmark** value is the *SEIN* **Long Run Marginal Cost ($/MW)**.

Both unit cost of service ($/MWh) include cost of investment, operation and maintenance and reflect a Present Value $/MWh.

The benchmark represents **standard costs** in the market, considering the specific risk of the project type (power generation), and it is not linked to the subjective profitability expectation or risk profile of a particular project developer.

That The Project is not the most inexpensive alternative in the market will be demonstrated in Sub-step 2c.

Sub-step 2c – Calculation and comparison of financial indicators[14]

Calculation of the levelized cost of The Project, which includes Investment (I) and Operation and Maintenance (O&M) Costs

Levelized Cost of The Project:
The formula to calculate the levelized cost is the following:

Cost per MWh = [Investment x CRF + O&M Annual] /Annual Generation (MWh)
Where,

Investment: Total investment in The Project ($) - not including VAT =$16.9 million

[14] Detailed data for calculation and modeling of Minimum Cost Expansion Plan is in Annex 3 under “Details of LRMC variables”.

In the present calculation the VAT is added but discounted by the fiscal credit, the final financial cost of this was calculated to be 4% over $16.250 Million, which gives $16.9 Million.

CRF: Capital Recovery Factor =0.14077

CRF =Equivalent Annual Cost of the Capital Investment/ Initial Capital Cost

CRF = Annuity of $16.9 million[15] at 14% discount rate and 40 years of annual payments[16] / $16.9 million

CRF= 2.379 / 16.9 = 0.14077

O&M: Annualized Operation and Maintenance costs. It does neither include financial costs nor income tax[17]. = 0.225 million

Includes variable costs (additives, lubricants, spares, materials and other maintenance expenses); and fixed costs (payroll expenses for employees in charge of the plant operation, plant supervision, plant maintenance, plant security and other general expenses)

Generation: Annual Average Generation in MWh = 57,740 MWh[18]

The calculation for The Project levelized cost is the following:

Levelized Cost for Poechos I

	Unit	The Project (Poechos)
Capacity	MW	15.2
Total Investment	$Million	16.9
Annual Cost:		
Capital	$Million	2.379
O&M	$Million	0.225
Total Annual Cost	$Million	2.604
Plant Factor	%	43.36%
Generation	MWh	57,740
Levelized Cost	**$/MWh**	**45.09**

Source: Single parameters where provided by The Sponsor. The calculation of the levelized cost is own production.

$2.379 million = Annual Equivalent Cost of the Capital Investment[19]

[15] Being 16.9 the Present Value of the Annuity.

[16] And Zero ending Cash Balance.

[17] For the latter will depend on an unknown variable which is The Project net income.

[18] The Project's estimated annual generation of 57,740 MWh. (calculated with a installed capacity of 15.2 MW) includes losses in transmission but does not included losses in distribution, according to The Sponsor. Moreover, Poechos I electricity meter is located in the Sullana Substation which means that all electricity registered by The Project includes already the losses that occur in the 38-Km transmission line (losses in transmission). The only reason why The Project's losses in distribution were considered to be zero for the calculation of The Project's levelized cost was: Conservatism. If losses in distribution had been considered in The Project's levelized cost calculation, the levelized cost of The Project would have gone up. This is because the levelized cost of The Project is calculated as the Equivalent Annual Cost of The Project divided by The Project's annual electricity dispatched to the *SEIN*. If the denominator had been decreased ("generation minus losses in transmission **minus losses in distribution**") the ratio would have gone up and The Project would have shown to be even less financially attractive than it was demonstrated to be in the Investment Analysis. Losses in distribution depend on the MW distributed. For The Project, losses in distribution are estimated to be within 1%-2%, according to the Sponsor. Considering this range the project levelized cost would be within 1% and 2% higher than $45.09/MWh, which gives a levelized cost within $45.55/MWh and $46.01/MWh.

+\$0.225 million = Annualized O&M
2.604 million
2.604 million / 57,740 MWh= **\$45.09 / MWh**

Calculation of the LRMC of the *SEIN,* which includes Investment (I) and Operation and Maintenance (O&M) Costs

The Long Run Marginal Cost of the *SEIN* (LRMC):

The LRMC (\$/MWh) is the equivalent cost per MWh estimated to supply the additional demand of the *SEIN* in future years (2007-2017, for this forecast). This cost includes Investment and Operations and Maintenance costs. The LRMC is calculated taken into account the additional future demand and the cost incurred to serve that demand, with Investments in new plants and the Operational and Maintenance cost of both new and existent plants (according to a dispatch simulation). The LRMC calculation considers that the new capacity addition installed will be fulfilled with the most economically efficient alternatives available in the market.

The LRMC was calculated by using the Wien Automatic System Planning Package (WASP). The WASP generated sequences of projects that comply with limit values for maximum and minimum reserves for each alternative technology specified. The WASP targets at minimizing the LRMC of the *SEIN.*

The LRMC uses the following formula:

$$LRMC = \frac{\sum_{i=1}^{n} \frac{I_i}{(1+r)^i} + \sum_{i=1}^{n} \frac{O\&M_i}{(1+r)^i} + \sum_{i=1}^{n} \frac{NSE_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{D_i}{(1+r)^i}}$$

Source: *MINEM*

Where[20],

I:	Sum of Equivalent Annual Investment Costs for a year
O&M:	Annual Costs in Operation and Maintenance
NSE:	Annual Losses in Distribution and Transmission
D:	Annual Demand Projected
r:	Discount rate: 14%
n:	2007-2017

[19] In Excel [PMT (14%, 40, 16.9, 0)] = Annuity of \$16.9 million at 14% discount rate and 40 years of annual payments, being \$16.9 million the Present Value of the Annuity.

[20] The detailed description of the variables and sources for their values can bee seen in Annex 3.

Calculation of LRMC of The *SEIN*

Year	Demand GWh	Incremental Demand GWh	I[21] 1000$	O&M[22] 1000$	NSE 1000 US$	Total Cost 1000 US$
2006	23219.4	-	-	-	-	-
2007	24061.9	843	8,853	14,740	0	23,593
2008	24935.4	1,716	36,165	9,770	0	45,935
2009	25789.3	2,570	36,165	34,340	0	70,505
2010	26681.4	3,462	45,018	48,480	0	93,498
2011	27587.9	4,369	72,329	47,190	0	119,519
2012	28548.6	5,329	72,329	67,870	0	140,199
2013	29539.3	6,320	108,494	75,870	0	184,364
2014	30563.2	7,344	108,494	92,510	0	201,004
2015	31618.3	8,399	108,494	113,000	0	221,494
2016	32709.9	9,491	117,347	137,600	0	254,947
2017	33839.2	10,620	144,658	145,150	0	289,808
NPV (14%)		20,435	296,326	260,281	-	556,607
LRMC	**27.24**	**$/MWh**				

Source: Peru's Sectoral Baseline Study (2003)[23]

556,607/20,435 = $27.24
The resulting LRMC of the *SEIN* was $27.24 /MWh.

Comparison: Both the LRMC and the Project levelized cost are comparable because they have the same nature of components (both I and O&M) and both reflect a present value of $/MWh. Since The Project has a higher cost indicator than the benchmark, $45.09 per MWh is greater than $27.24 per MWh, The Project cannot be considered financially attractive.

Sub-step 2d. Sensitivity Analysis
The following variables will undergo a sensitivity analysis to prove the robustness of the conclusion given in Sub-step 2c.
For the *SEIN* LRMC ($/MWh)[24]:
a) Annual Investment Costs
b) Discount Rate

For The Project Levelized Cost ($/MWh):
a) Load Factor
b) The Initial Investment Cost
c) Discount Rate

[21] Equivalent Annual Cost of Capacity Additions selected by WASP.
[22] Simulation of future supply to attend the projected demand was forecasted by WASP.
[23] Developed by a *MINEM* expert in 2003.
[24] Note that a sensitivity analysis can not be performed for the LRMC Load Factor, because in the LRMC calculation, the load factor varied per plant, per month, and per year.

Sensitivity Analysis for the *SEIN* LRMC ($27.24/MWh)
(a) Annual Investment Cost and (b) Discount Rate.

SENSITIVITY ANALYSIS FOR THE *SEIN* LRMC (2007-2017)

	Incremental GWh				EAI=Eq.Annual Invest Cost			Discount Rate Sensitivity								
				Data		r=0%		90%*I			100%*I			120%*I		
Y	12%	14%	16%	r=0%	90%	100%	120%	12%	14%	16%	12%	14%	16%	12%	14%	16%
2007	672	649	626	**843**	21,234	**23,593**	28,312	16,927	16,339	15,780	18,808	18,154	17,533	22,570	21,785	21,040
2008	1221	1158	1099	**1,716**	41,342	**45,935**	55,122	29,426	27,904	26,486	32,696	31,005	29,429	39,235	37,206	35,314
2009	1633	1522	1419	**2,570**	63,455	**70,505**	84,606	40,326	37,570	35,045	44,807	41,745	38,939	53,769	50,094	46,727
2010	1964	1798	1648	**3,462**	84,148	**93,498**	112,198	47,748	43,704	40,064	53,053	48,560	44,516	63,664	58,272	53,419
2011	2213	1990	1793	**4,369**	107,567	**119,519**	143,423	54,497	49,006	44,150	60,552	54,451	49,056	72,662	65,341	58,867
2012	2411	2130	1886	**5,329**	126,179	**140,199**	168,239	57,077	50,426	44,646	63,419	56,029	49,607	76,103	67,235	59,528
2013	2553	2216	1928	**6,320**	165,928	**184,364**	221,237	67,015	58,167	50,612	74,462	64,630	56,236	89,354	77,557	67,483
2014	2648	2258	1931	**7,344**	180,904	**201,004**	241,205	65,236	55,629	47,569	72,484	61,810	52,855	86,981	74,172	63,426
2015	2704	2266	1904	**8,399**	199,345	**221,494**	265,793	64,184	53,772	45,188	71,315	59,747	50,209	85,578	71,696	60,251
2016	2728	2246	1855	**9,491**	229,452	**254,947**	305,936	65,962	54,292	44,839	73,291	60,325	49,821	87,949	72,390	59,785
2017	2726	2204	1789	**10,620**	260,827	**289,808**	347,770	66,948	54,137	43,940	74,386	60,152	48,822	89,264	72,183	58,586
	23,475	20,436	17,879		**NPV of Annual Investments=**			575,346	500,947	438,319	639,274	556,608	487,021	767,128	667,930	584,426

90%*I	12%	24.51		
	14%		24.51	
	16%			24.52
100%*I	12%	27.23		
	14%		27.24	
	16%			27.24
120%*I	12%	32.68		
	14%		32.68	
	16%			32.69

Source: Own production

The SEIN *LRMC* is not sensitive to the discount rate but it is to the Annual Investment Cost.

Sensitivity analysis for The Project ($45.09/MWh)
(a) Load Factor.

LEVELIZED COST FOR POECHOS

40 years of payment 16.9 Investment Cost 14% Discount Rate		LF 100%	Change in Load Factor (LF*%) all else constant 120%	110%	90%	80%
Capacity	MW	15.2	15.2	15.2	15.2	15.2
Total Investment	$Million	16.9	16.9	16.9	16.9	16.9
Annual Cost:						
Capital	$Million	$2.38	2.38	2.38	2.38	2.38
O&M	$Million	0.225	0.225	0.225	0.225	0.225
Total Annual Cost	$Million	$2.60	2.604	2.604	2.604	2.604
Plant Factor	%	43.36%	52.04%	47.70%	39.03%	34.69%
Generation	MWh	57,740	69,287	63,513	51,966	46,192
Levelized Cost	**$/MWh**	**45.09**	**37.58**	**40.99**	**50.10**	**56.37**

Source: Own production – The Sponsor provided single parameters.

(a) Load Factor, (b) Initial Investment Cost and (c) Discount Rate Sensitivity Analysis Matrix:

EAI Capital Cost	15.21	I*90%	12%	($1.85)	($1.85)	($1.85)	($1.85)
Figures are in red only			14%	($2.14)	($2.14)	($2.14)	($2.14)
because they represent			16%	($2.44)	($2.44)	($2.44)	($2.44)
outflows (costs)	16.9	I*100%	12%	($2.05)	($2.05)	($2.05)	($2.05)
			14%	($2.38)	($2.38)	($2.38)	($2.38)
			16%	($2.71)	($2.71)	($2.71)	($2.71)
	20.28	I*120%	12%	($2.46)	($2.46)	($2.46)	($2.46)
			14%	($2.85)	($2.85)	($2.85)	($2.85)
			16%	($3.25)	($3.25)	($3.25)	($3.25)
Total Eq.Annual Cost	15.21	I*90%	12%	2.070	2.070	2.070	2.070
			14%	2.366	2.366	2.366	2.366
			16%	2.665	2.665	2.665	2.665
	16.9	I*100%	12%	2.275	2.275	2.275	2.275
			14%	2.604	2.604	2.604	2.604
			16%	2.936	2.936	2.936	2.936
	20.28	I*120%	12%	2.685	2.685	2.685	2.685
			14%	3.079	3.079	3.079	3.079
			16%	3.478	3.478	3.478	3.478
Levelized Cost	15.21		12%	29.88	32.59	39.83	44.81
			14%	34.14	37.25	45.53	51.22
			16%	38.46	41.96	51.28	57.70
	16.9		12%	32.83	35.82	43.78	49.25
			14%	37.58	40.99	50.10	56.37
			16%	42.38	46.23	56.50	63.56
	20.28		12%	38.75	42.28	51.67	58.13
			14%	44.44	48.48	59.26	66.66
			16%	50.20	54.77	66.94	75.30

Source: Own production

Comparing all Levelized Cost obtained with all benchmarks obtained:

Benchmark- Not efficient Market	Change in Investment for Poechos	Discount Rate for Poechos	**Change in Load Factor for Poechos (LF*%)**			
			120%	**110%**	**90%**	**80%**
Max EAI for the SEIN	15.21	12%	Not Additional	Not Additional	Additional	Additional
32.69		14%	Additional	Additional	Additional	Additional
16% discount rate		16%	Additional	Additional	Additional	Additional
120% Investment Cost	16.9	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional
	20.28	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional

1) Poechos is more efficient than the market when its LOAD FACTOR increases to 52.04%, faces DISCOUNT RATE of 12% and its I is reduced in 10% to $15.21 million (since the latter is not plausible, this scenario can be discarded)
2) Poechos is more efficient than the market when its LOAD FACTOR increases to 47.7%, faces DISCOUNT RATE of 12% and its I is reduced in 10% to $15.21 million (since the latter is not plausible, this scenario can be discarded)

Benchmark- Base Scenario Market	Change in Investment for Poechos	Discount Rate for Poechos	**Change in Load Factor (I*%)**			
			120%	**110%**	**90%**	**80%**
Medium EAI for the SEIN	15.21	12%	Additional	Additional	Additional	Additional
27.24		14%	Additional	Additional	Additional	Additional
16% discount rate		16%	Additional	Additional	Additional	Additional
120% Investment Cost	16.9	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional
	20.28	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional

Source: Own production

Benchmark- Most efficient Market	Change in Investment for Poechos	Discount Rate for Poechos	Change in Load Factor (I*%)			
			120%	**110%**	**90%**	**80%**
Min EAI for the SEIN	15.21	12%	Additional	Additional	Additional	Additional
24.52		14%	Additional	Additional	Additional	Additional
16% discount rate		16%	Additional	Additional	Additional	Additional
120% Investment Cost	16.9	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional
	20.28	12%	Additional	Additional	Additional	Additional
		14%	Additional	Additional	Additional	Additional
		16%	Additional	Additional	Additional	Additional

Source: Own production

All combination for both scenarios, indicate that The Project is additional except for only two cases. These are when comparing with a Not Efficient Market Benchmark ($32.69), and **r=12%**, The Project **Initial Investment Cost goes down by 10%** and **Load Factors for The Project go up in 10% and 20%, respectively -** These two scenarios can be discarded because it was not possible to decrease the cost of The Project less than $16.9 million.

Both benchmarks, the Medium Efficiency Scenario for the Market and the Most Efficient Scenario for the Market, show that The Project is additional at all discount rates, at all load factors and at all initial investment costs, considered for it.

Since The Project's financial unattractiveness, concluded in Sub-step 2.c., has proved to be robust to reasonable variations in the critical assumptions, The Project is unlikely to be financially attractive – Meaning the Project is additional under Step 2.

Step 3. Barrier Analysis

Sub-step 3 a. Identify barriers that would prevent the implementation of the type of the proposed project activity

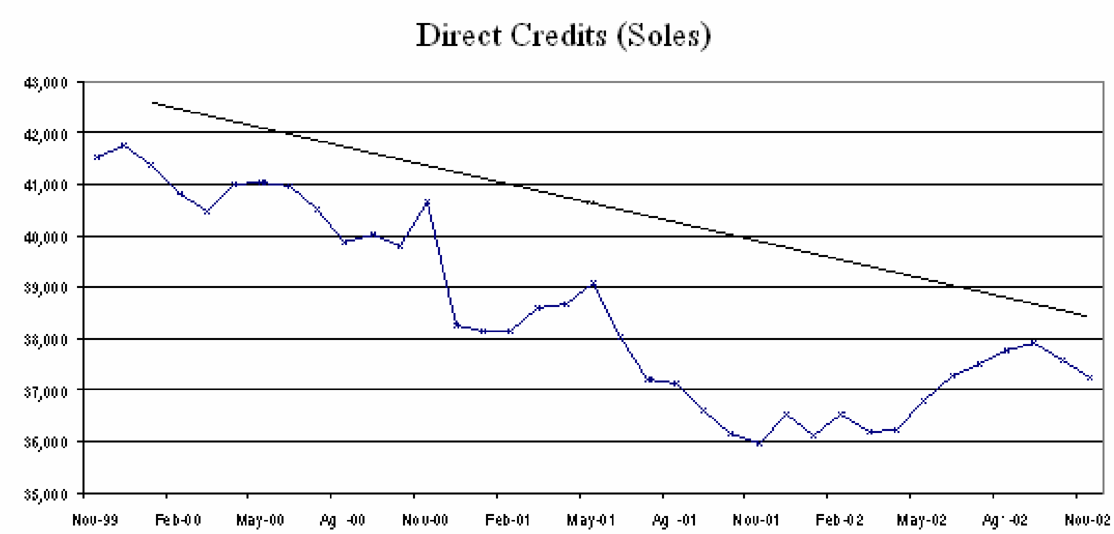
Hydropower plants projects face several types of barriers that prevent them from being carried out if they are not registered as CDM activities. The barriers The Project faced were basically two:

1) A still depressed international investment climate towards emerging markets when The Project started construction in late 2002: A worldwide flight-to-quality phenomenon affected Peru from late 1998 – in 2 ways, preventing international investors to lend to the Peruvian banking system and preventing the Peruvian banking system to lend to highly leveraged projects (commonly highly capital intensive projects) that do not have large companies as project developers (The Project case). The flight to quality worldwide phenomenon was triggered by the successive global emerging markets crisis, which started in 1997[25], "private capital flows to emerging markets had all dried up by 2001"[26]. Graphs below show the effects of the emerging market crisis. The Project Developer was counting with the CERs before October 2002 -a preliminary PDD was elaborated in February 2002- thus the promise of this future revenue helped to cope with the international climate. The loan agreement to fund The Project was signed in October 2002 fully integrating Carbon Finance cash flows in the financial models.

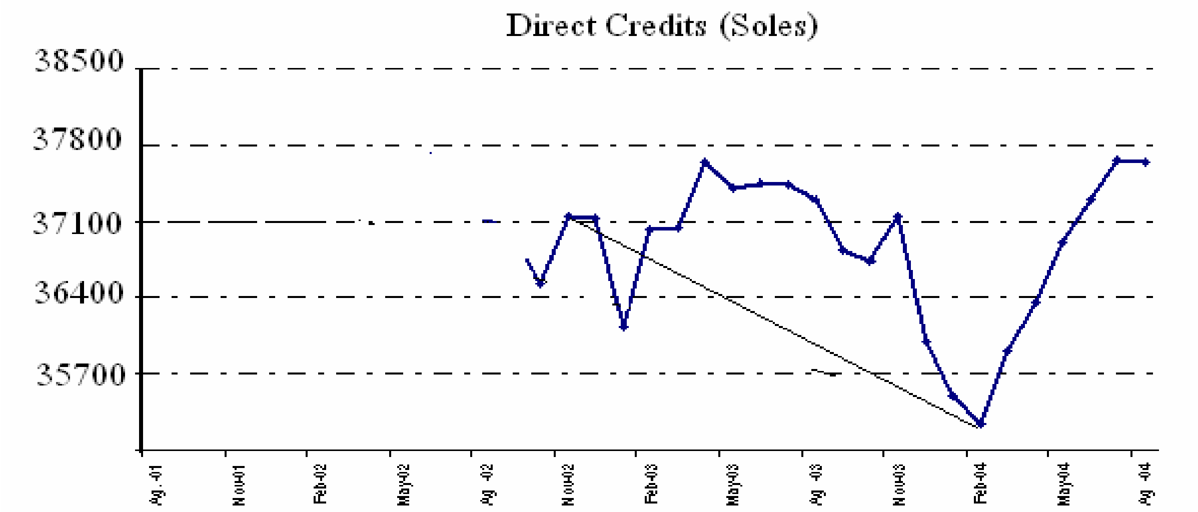
[25] Thailand crisis, July 1997; Russian Crisis August 1998; Brazil devalues and floats in February 1999; Turkey floats the lira in February 2001; Argentina defaults in December 2001 – Following the successive crises in Asia (1997) and Russia (1998).
[26] The Unholy Trinity of Financial Contagion, by Kaminsky, Reinhart, and Vegh; Journal of Economics Perspectives – Volume 17-Number 4 – Fall 2003 - pg 63.

Net Private Capital Inflows (1985-2003)-(Billions of $)

Source: IMF, World Economic Outlook.



Source: Peruvian Banking and Insurance Superintendence - Nov 2002 Statistics.



Source: Peruvian Banking and Insurance Superintendence - August 2004 Statistics.

2) Government policies pro-Camisea natural gas project and pro- natural gas-based electricity generation: The Peruvian Government had proven to be fickle in the past regarding the Camisea Project[27] as shown by its relationship with Shell - policies and acceptance towards the Camisea Project were highly dependent on the Presidential regime. However after the exit of Shell in July 1998, the successive governments have adopted a clear "pro-Camisea" position, granting a series of guarantees and incentives. The Project started constructions works in November 2002, thus it was affected by **Law 27133 – Law of Promotion of the Natural Gas Industry issued in June 4, 1999, in force as of today - after laws that have slightly modified it: DS 034-2001-EM (issued in July 2001), DS 018-2000-EM (issued in October 2000). The Project has also started construction after several incentives were already given and/or readily in place regarding promotion in the continuity of the Camisea gas project and in electricity generation based on natural gas - i.e. Take or Pay ("TOP") contract signed in December 2000.**

The Camisea chronology is the following:
a) During the Fujimori Regime (1990- August 2000): After the exit of Shell, in mid 1998, the Government decided to promote thermal technology based on natural gas, from that same year it halted the definitive and temporal concessions for hydropower plants through: Law 26980 issued in September 1998, Law 27133 issued in June 1999, and Law 27239 issued in December 1999[28]. No hydropower plants definite concessions were granted in the years 1999 to 2000[29], showing the clear impact and determination of the Fujimori's Laws against hydropower plants developments. In May 1999, the Special Committee for The Camisea Project (CECAM) called for an international public bid to award the license agreement for the Camisea Gas Exploitation, as well as the concession for liquids and gas transportation to the coast and gas fuel distribution in Lima and CalIao. In February 2000, pursuant to an international public bid, Fujimori's Government awarded the license for the exploitation of the Camisea Fields (Upstream) **to the Consortium Pluspetrol**, led by Pluspetrol Peru Corporation S.A (the operator), with the participation of Hunt Oil Company of Peru L.L.C., SK Corporation and Tecpetrol del Peru S.A.C. (fully owned by Techint Group, an Argentinean group). The license was awarded based on the highest royalty rate offered[30] - The Upstream Project consists of a 40-year license for the extraction of natural gas and liquid hydrocarbon.

b) The Transitional Government of President Valentin Paniagua (set 2000-July 2001), derogated the Law 27239 Unique Complementary Disposition given by Fujimori against hydropower plant development through the Law 27435 (Hydropower Plants Concessions Promotions Law) in March 15th, 2001. But just months before the release of the issuance of Law 27435, in October 2000, the presidential regime had awarded the concessions for liquid and gas transportation to the coast and gas distribution in Lima and Callao (Downstream) **to The Consortium TGP[31]**, led by Tecgas N.V (the operator and fully owned by Techint Group), with the participation of Pluspetrol Resources Corporation, Hunt Oil Company, SK Corporation, Sonatrach Petroleum Corporation B.V.I and Graña y Montero S.A. The Downstream includes three different 33-year contracts: a contract for the transportation of gas from

[27] San Gaban II and Yuncan hydropower plants' constructions in 1998 show a no clear political promotion towards gas by that time of the Fujimori Government. These 2 hydroelectric power plants would produce daily the same as a natural gas-fired plant generation that uses 50 MMCFPD (almost the volume sell guaranteed under the Camisea Take or Pay contract). Between 1983 and 1987 as a result of drilling 5 exploration wells, Shell discovers the Camisea Gas Fields. In July 1998 the consortium Shell-Mobil announces its decision of abandoning the negotiations with Peruvian Government and, thus the contract is terminated.
[28] The detail of these three laws against hydropower plant development can be seen under section A.4.4.
[29] Source: Last-10-year list of definite concessions granted by the *MINEM*.
[30] The consortium Pluspetrol offered the highest royalty rate, 37.24%.
[31] Transportadora de Gas Del Peru S.A (TGP) is the company formed by the consortium specifically created for the development and operation of The Camisea Project Downstream.

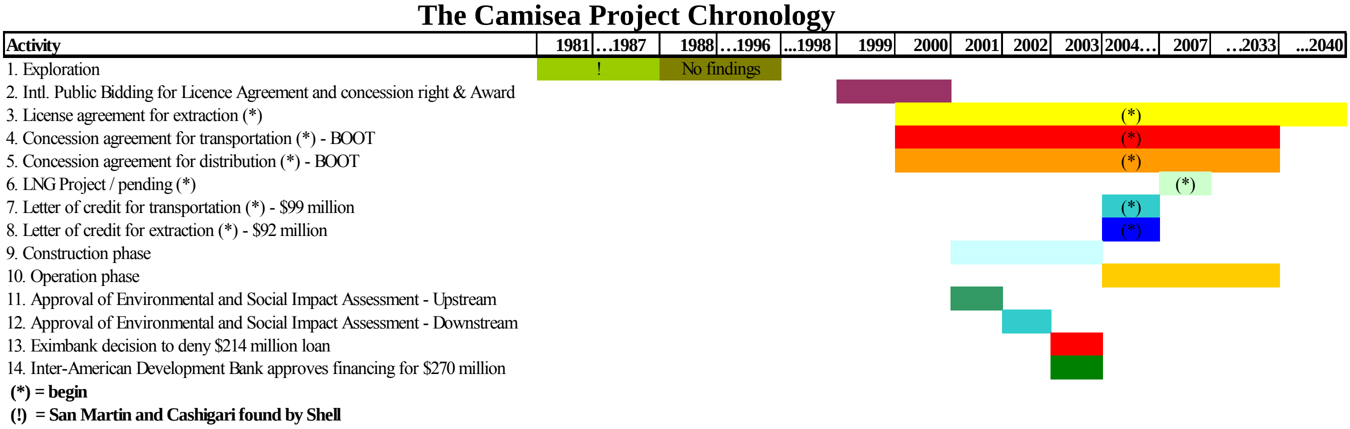
Camisea to Lima, a second one for the transportation of natural gas liquids from Camisea to the coast and a third one for the distribution of gas in Lima and Callao. They were awarded on the basis of the lowest service cost offered.

In December 2000, The Peruvian Government represented by Electroperu, stated owned generation enterprise, acquired an important commitment aiming at providing an extra incentive for The Camisea Project. This is the contract of supply of natural gas for electricity generation ("Take or Pay" or TOP). This contract indeed fostered this Mega Project, because it meant a commitment to pay close to $20 million annually for natural gas for electricity generation purposes regardless of whether it be consumed or not[32]. The TOP contract aimed at helping investors in Transportation and Distribution to achieve their projected IRR of 12%, the government also allowed an increase the regulated price to the final client, for this end. On the other hand, the scheme for the Extraction business was setting maximum prices of natural gas on-site (for the electricity sector: Max Price of 1.00 US$/MMBTU for other sectors: Max Price of 1.80 US$/MMBTU, for exports 0.6 US$/MMBTU to make it competitive internationally).

c) The current government of President Toledo (2001-2005), continues fostering thermal technology based on natural gas. In early in May, 2002, The Consortium TGP selected Tractebel as operator of the Gas Distribution Company[33]. Tractebel became a partner in the Consortium TGP (with 8% ownership). The gas distribution[34] concession in Lima and Callao was granted to the company Tractebel through a Built on Operate and Transfer ("BOT") Contract.

In August 2003, Electro Peru transferred the TOP contract to Etevensa, through public bid. This concession also committed Etevensa to sell its total energy generation to ElectroPeru at a relatively low price **($23.9 per MWh monthly for the first 7 years of contract)**, and committed Etevensa to an investment agenda in gas plants[35]. Etevensa consumption is estimated to be 70 MMCFPD, from which 80% (56 MMCF/D) would be under the TOP – Etevensa is allowed to reduce this volume by 10% to 50.4 MMCFPD.

The Camisea Project Chronology



Source: Own production with *MINEM* information

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[32] The TOP contract established a discount of 10% in the on–site price with respect to the price established for the other electric generators.
[33] GNLC (Natural Gas of Lima and Callao) is a Tractebel-owned Company, created to develop the natural gas distribution service in Lima and Callao.
[34] The distribution starts from the City Gate and goes to Ventanilla. Later on, the distributor (Tractebel) will have to construct additional pipelines of low and high pressure for industrial and commercial clients according to the increase in demand.
[35] Electro Peru transferred the Take or Pay contract to Etevensa, through public bid, the winner was conditioned to the installation of a 320 MW power plant: 2 gas turbine units of 125 MW each one and one steam unit of 62.5 MW. ETEVENSA, as the owner of the Ventanilla Thermal Plant, would use its 2 installed units of 160 MW (which it had to convert to be able to function with natural gas), and will add a steam 65 MW unit over by 2006. The government still holds a minority stake in such company.

The impact of this government-driven project in electricity prices is devastating for hydropower developers which now have to compete not only with a cheaper technology available (combined cycle plants) , but also with a much cheaper national fuel.

The government has also announced in October 2004 its intention to promote a new 300-500 MW natural gas fired power plant. Furthermore, regulatory and economical incentives recently given by the Peruvian Government include the following laws, already present under section A.4.4 of the present document. These law directly promote electricity generation based on natural gas.

- **June 25, 2004: DS 019-2004,**
- **August 5, 2004: DS 107-2004-EF,**
- **November 24, 2004: DS 041-2004-EM.**

According to the *MINEM*[36], the foreseen Camisea impact scenarios[37] in the Peruvian electricity industry are two:
1) Hydro-thermal Scenario: At the end of 2027, the *SEIN* will have an installed capacity 66% thermal and 34% hydro. The current situation of the installed capacity of the *SEIN* is 40% thermal and 60% hydro.
2) Thermal Scenario: If all the additions in electricity generation were going to be natural gas-fired thermal plants, at the end of 2027 the *SEIN* would have an installed capacity 75% thermal and 25% hydro.

In both scenarios, the electric sector would be the main consumer of the Peruvian natural gas industry. In the hydro-thermal scenario the demand would be 800 MMCFPD, and in the thermal scenario would be 1000 MMMCFPD.

From this forecast it can be concluded that Peru's baseline in the future is Natural Gas.

Sub-step 3b. Show how the identified barriers would not prevent the implementation of at least one of the alternatives
-The still depressive International Investment Climate towards emerging markets when The Project started construction (Barrier 1):
-Affected less strongly natural gas project developments (Alternative 2) because of three reasons:
- The lower investment needed to build a natural gas-fired power plant. A hydropower plant investment is needier of financing than a gas-fired power plant because of the much higher up-front investment cost needed for the prior. The table below shows that the turnkey cost[38] per MW of a run-of-river hydropower plant ($975,000) is more than double that of a simple cycle gas power plant ($475,000), on average.

[36] *MINEM*-Electricity General Directive, http://www.minem.gob.pe/electricidad/estadisticas/informativo/informativo8.pdf
[37] Considering a 4.6% annual demand increase.
[38] Turnkey meaning the investment needed to put a power plant in operation.

Technology Comparison	Simple Cycle Gas Turbine	River Hydro
Size Range (MW)	0.5 - 450	.02 - 1
Efficiency (%)	21% - 45%	60-70%
Gen Set Cost ($/MW)	300,000 to 600,000	NA
Turnkey Cost-No Heat Recovery ($/MW)	**300,000 to 650,000**	**750,000 to 1,200,000**

Source: Meherwan P. Boyce, Ph.D, P.E (2002); "Gas Turbine Engineering Handbook", p.8

-The faster time it takes to put the brand-new engines in operation for the natural gas-fired power plant, which exposes lenders to less risk.

-The shorter time it takes in recovering the initial investment made which exposes lenders to less risk.

-Does not prevent "not implementing any power generation project" (Alternative 3), but in fact fosters it. Evidence of this is provided in the Newly Built 1998-2003 power plants table, shown under the Common Practice Analysis, in which it can be seen that the 3-year average of new capacity additions in the *SEIN* has decreased in 92% in the 3 most recent years (2001-2003) when compared with the previous three years (1998-2000) [39].

-Barrier due to prevailing practice (Barrier 2):

-Do not prevent the implementation of natural gas fired power plants (Alternative 2). In fact natural gas power fired plants is the beneficiary of all these policies and government interventions in the electricity market and energy sector from the second half of 1998.

-Do not impose penalties to "not investing"(Alternative 3), thus Alternative 3 is not prevented by Barrier 2 either.

Since the alternatives are affected less strongly/not prevented by the identified barriers that The Project faced, they are both viable alternatives and should not be eliminated from consideration.

Having been identified two barriers that prevented the implementation of this type of proposed project activity (hydropower plants) but did not prevent/affect less strongly at least one of the alternatives identified, the project is additional under Step 3.

Step 4. Common Practice Analysis

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

Hydro-generation barriers started in the second half of 1998 because of both 1) a depressed international investment climate towards emerging markets which has not favored highly capital intensive projects developments (as hydro are) access to financing, and 2) the determining governmental pro-Camisea position that started in 1998 after the exit of the Shell-Mobil. It is from the second half of 1998 that hydro development can not be considered anymore common practice. The situation for hydro power plants projects has kept worsening, as long as more governmental guarantees have been offered to the Camisea Project. Although it can not be said that the emerging market conditions will not improve in the future, it can certainly be said that hydro development participation in power generation installed capacity will keep shrinking until 2027- based on *MINEM forecasts*, because of the Camisea Project occurrence.

[39] Being the average annual capacity additions in 1998-2000, 275.87 MW, and 20.93 MW in 2001-2003.

All newly built hydropower plants that started operations from 1998 and all in-construction hydropower plants as of today, **except for CDM project activities** will be analyzed in this section. In addition, gas projects (Alternative 2) and the no implementation of any electricity generation project (Alternative 3) will be discussed under this Sub-Step (4a.)

The List of electricity generation newly built plants from 1998 and in-construction projects in Peru is provided below:

In-construction projects (and their project generation by 2008[40])

Plants in construction	Situation	Additions in Installed Capacity (MW)	Technology	Estimated Annual Generation (GWh)
2004				
SANTA ROSA II	In construction	1.3	Hydro	6
VENTANILLA TG3	Conversion	164.1	Gas	697
VENTANILLA TG4	Conversion	160.5	Gas	1,440
2005				
YUNCAN	In construction	130	Hydro	909

Source: Own production with data of *GART* (4-year projections of May 2004) and *MINEM* projection for generation of Santa Rosa II

***SEIN* Capacity Additions from 1998 to 2003**

Years	Techn	Addition Category	Install.Cap. Added (MW)
1998			
AGUAYTIA 1	DRY GAS	Newly built	86.3
AGUAYTIA 2	DRY GAS	Newly built	86.3
TG MALACAS	PM GAS	Newly built	102.2
1999			
SAN GABAN II	HYDRO	Newly built	55.0
CALANA	R6	Newly built	6.4
MOLLENDO TGM	D2	Newly built	90.0
2000			
SAN GABAN II	HYDRO	Newly built	58.1
ILO2 TVC	COAL	Newly built	145.0
C.H. CHIMAY	HYDRO	Newly built	156.0
C.H. YANANGO	HYDRO	Newly built	42.3
2001			
TUMBES	R6	Newly built	18.3
2002			
C.H. HUANCHOR	HYDRO	Newly built	18.9
2003			
YARINACOCHA	R6	Newly Built	25.6

Source: Own production

<u>Analyzing hydropower plants development (Alternative 1):</u>
Newly built hydro power plant that started operation since 1998 cannot be considered common practice, but rather sporadic especial conditions of the projects' developers.

-Yuncan Project (will start operations in 2005):

TheYuncan Project recent sponsor: Tractebel, has planned to obtain CDM Status and is currently working on that process, a communication letter about this intention has been provided to the World Bank. However, as the application is not yet advanced this project will still be analyzed below:
The Yuncan Project, a 130 MW hydropower plant, was developed and fully owned by the Peruvian Government until June 2004. It started construction 1997, during the Fujimori Regime. The Financing for this project was given by an external loan granted to the Peruvian Government by the Japan Overseas Economic Cooperation Fund – OECF[41]. The total investment in the project accounts for $262.7 million. This project has been paralyzed for a number of years due to promotion of natural gas technologies and large cost overruns. On June 2004, the Government of Peru – in accordance with the local authorities of the Pasco region - granted to Enersur (Tractebel generation investment in Peru) a 30-year concession for the Yuncan hydropower plant and associated transmission facilities, keeping the same financial conditions for the new concessionary. The plant is currently under construction and is located in the

[40] Year in which annual generation of these projects stabilizes (especially that of the natural gas projects).
[41] This institution lends only to governments, at very low interest rates.

Pasco Region, Central Peru, 340 km to the North East of Lima. The overall construction progress is 70% and the commissioning is estimated for July 2005. Under the usufruct agreement, Enersur has the exclusivity to operate the plant and sell the energy it generates. The financing is already given and will keep the same terms, this was a critical issue that motivated Tractebel to invest in this hydropower plant - Enersur's offer for Yuncan was approx. $53 million to be paid over the next seventeen months. Yuncan is not comparable to SINERSA for three reasons: **1) When the government started the construction of Yuncan the international climate was not depressed as it was in 2002, 2) also Camisea was not a major strategic target of the government by that time, and 3) For Yuncan, the government access to financing (1997) is the same access to financing enjoyed by Tractebel (2004) as the government continued being the guarantor for the loan of the OECF - This is not comparable to SINERSA's access to financing.**

-Santa Rosa II Project (has started operations in 2004):

Its application to obtain CDM Status is relevantly advanced, therefore this project will not be analyzed further. Santa Rosa II is a micro hydropower plant, 1.5 MW. Its sponsors applied to The World Bank to attain CDM status in early 2003. Application is **currently being processed as part of the Community Development Carbon Fund (CDCF) and Santa Rosa II will be treated as a small scale project.**

-Huanchor Hydropower plant (2002):

Huanchor (18.9 MW) started construction in 1999. It is owned by The *Grupo Gubbins*. The *Grupo Gubbins* is a large Peruvian investment group[42]. The sponsor purpose was to use hydro resources that were available close to its mines. Thus, the financial returns on that project were enhanced by savings in actual electricity expenses of the sponsors' mines (which consumes an important proportion of total Huanchor total generation). As natural gas was not available in the area surrounding the sponsor mines, the cheaper option was to build a hydropower plant. **Because of the synergies Huanchor provides to its sponsor, Huanchor is not comparable to The Project. SINERSA is also not financially comparable to the *Grupo Gubbins* regarding access to financing.**

-Chimay (2000) and Yanango (2000) Hydropower Plants:

Commonly called "Chinango", Chimay and Yanango account for 198.3 MW of installed capacity. The total investment was $200 million approx. The projects started constructions works in 1997, and were developed simultaneously by Edegel. Both are located approximately 125 miles east of Lima. The projects are separate facilities but do share a common transmission line, a new 120 kilometer, and a 220 kV line. This large investment was started just before the emerging markets crisis that strongly hit L.A from 1998[43] and in view of a good financial situation enjoyed by the sponsors, by 1997. Endesa Chile is a 37% Edegel shareholder. Enersis is a 60% Endesa-Chile shareholder, and Endesa-Spain is a 65% Enersis shareholder. Enersis' and Endesa's revenue for year 2003 were $3,998,967,000 and $20,899,871,000 respectively**. Both sponsors are not comparable to The Project's sponsor in access to financing, as of today, and they were certainly in a superior financial standing in 1997. Also the Chinango Project's sponsors enjoyed a better international investment climate in 1997 than SINERSA did in 2002. The Projects started construction works prior to pro-Camisea policies.**

-San Gaban II (1999, 2000) Hydropower Plant (2 units):

Units **developed and fully owned by the government** (as of today), the San Gaban II hydropower plant with an installed capacity of 113.1 MW[44] started its preliminary construction works in 1995. In May 1996, the civil works were called into a public bid. The winner was a Peruvian-Brazilian-French Consortium that **started civil works in September 1996** and took 3 years to finish them. San Gaban II was concluded in 1999. The external financing was $155 million approx., granted by The Japan Bank for International Cooperation ($130 million) and the CAF ($25 million). The total cost of this project was

[42] Which has stakes in Sociedad Minera Corona (assets of $36.06 Million up to June 2004), Sociedad Minera La Cima (assets for $19.8 Million up to June 2004) and Inversiones Agricolas S.A (asset information not publicly available).
[43] Russian crisis.
[44] Two units of approximately the same installed capacity.

$208 million. San Gaban II, is currently under 100% ownership of the Peruvian Government through FONAFE (*Fondo Nacional de Financiamiento de la Actividad Empresarial del Estado*).

Discussing natural gas-fired power plants development (Alternative 2):

-Ventanilla TG3 and Ventanilla TG4 (2004):

Ventanilla TG3 and TG4 are the first plants built to use Camisea's natural gas, and are property of Etevensa; furthermore in May 2006, the gas combined cycled technology will be ready to operate in Ventanilla TG4. These plants respond to Pro-Camisea governmental policies because Etevensa was committed to install a 320 MW gas-fired power installed capacity in order to win the transferal of Camisea's Take or Pay Contract from ElectroPeru[45].

-TG Malacas and Aguaytia 1 and 2 (1998):

These plants have been developed by the private sector, and by using the only two discovered gas wells in Peru besides Camisea. Although, they are not consequence of the Camisea circumstance, they show that gas per se is an attractive generation technology in Peru. The Aguaytia gas price does not differ greatly from the Camisea Gas price that is set for electricity generators consumers.

After the commercial operation of Ventanilla TG3 and TG4 in August 2004, it is foreseen that other large scale gas-fired power plants concessions requests will be presented to the *MINEM*.and granted[46]; Alternative 2 is plausible to become a common practice.

Discussing the no implementation of any power generation project (Alternative 3):

-In the Newly Built 1998-2003 power plants table shown above it can be seen that the 3-year annual average of new capacity additions in the *SEIN* has decreased in 92% in the 3 most recent years (2001-2003) when compared with the previous three years (1998-2000)[47]. This proves that the country can experience also scarcity in generation projects, in certain years; Alternative 3 although plausible in certain periods of time is not likely to become a common practice because of market forces.

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

No similar activities (hydropower plants) in terms of access to financing, international investment climate or developed under the same clear governmental pro-Camisea position have been identified from 1998. The only hydro power plant development that can be comparable to The Project in regards to depressed international investment climate and starting construction after the clear pro- Camisea governmental position is Huanchor, but this project activity has essential distinctions with The Project, these distinctions have been analyzed in Sub-step 4a.

Since similar activities(hydropower plants) have essential distinctions with the project activity that can reasonably be explained and were exposed under Sub-Steps 4a and 4b, the claim that the proposed activity is common practice is not called into question. Therefore, The Project is not common practice but a very unusual occurrence that endangered its existence without attaining CDM Status. Meaning The Project is additional under Step 4.

Step 5. Impact of CDM Registration

CDM registration will alleviate the financial hurdles of The Project (**Step 2. Investment analysis)** since it would provide risk-free revenue[48], attached to The Project's annual generation. If CERs revenues are used to offset The Project's O&M annual costs, The Project's levelized cost will decrease and so will the

[45] The TOP is mentioned under Step 3 Barrier Analysis (Sub-Step 3.a.) faced by The Project.
[46] Tractebel's request of 360 MW approximately installed capacity and EGECHILCA's request of 520 MW approximately installed capacity are two of the most publicly known concession requests already made to *MINEM*.
[47] Being the average annual capacity additions in 1998-2000, 275.87 MW, and 20.93 MW in 2001-2003.
[48] Except for the CDM risk.

Project's financial unattractiveness. The Sponsor considered, before the Project investment decision was made[49] the potential impact of CDM Registration very important for The Project's financial viability due to the CERs potential high liquidity in the international market. At that point in time, there was an even higher uncertainty in the future CERs price.

As of today, taking a credible CERs price of \$5.63 per tCO_2e - which is the weighted average CERs price between January 2004 and April 2005[50] - CERs revenues could reduce The Project's financial gap (difference between The Project levelized cost and The *SEIN* LRMC) in 18%, going from a \$17.85/MWh[51] to \$14.56/MWh[52]-almost one fifth down of the financial gap the project faced without CERs revenues.

Price (US\$) 5.63

SENSITIVITY ANALYSIS FOR THE PROJECT LEVELIZED COST (\$/MWh)

40 years of payment 16.9 Investment Cost 14% Discount Rate		LF=43.36%	+ CERs 7 years	+ CERs 14 years	+ CERs 21 years
Capacity	MW	15.2	15.2	15.2	15.2
Cost	\$/KW	1,097	1,097	1,097	1,097
Total Investment	\$Million	16.9	16.9	16.9	16.9
Annual Cost:					
Income CERS	\$Million	\$0.00	(\$0.12)	(\$0.17)	(\$0.19)
Capital	\$Million	\$2.38	\$2.38	\$2.38	\$2.38
O&M	\$Million	0.225	0.225	0.225	0.225
Total Annual Cost	\$Million	\$2.60	\$2.48	\$2.43	\$2.41
Plant Factor	%	43.36%	43.36%	43.36%	43.36%
Generation	MWh	57,740	57,740	57,740	57,740
Levelized Cost	**\$/MWh**	**45.09**	**42.98**	**42.14**	**41.80**
CERs/yr (tCO2)	**31,463**	**Change in \$/MWh:**	**-4.68%**	**-6.55%**	**-7.30%**
Revenue/yr (\$)	**177,137**				

CER 7 years	PV of Revenue	\$865,962
	Equivalent Annual Revenue	\$121,880
	In millions	\$0.12
CER 14 years	PV of Revenue	\$1,212,033
	Equivalent Annual Revenue	\$170,588
	In millions	\$0.17
CER 21 years	PV of Revenue	\$1,350,336
	Equivalent Annual Revenue	\$190,053
	In millions	\$0.19

Source: Single parameters were provided by the Sponsor, calculations are own production.

Depending on future CERs price, the impact of carbon finance on the financial viability of the project could be even greater. i.e. Upon registration and promptly CERs sell in the EU ETS, as long as issues that explain the difference between the CERs price and the currently higher EUA price are overcome[53], The Project's CERs from the start of its crediting period (April 2004) up to December 2007 could achieve a higher-than-\$5.63 price, reducing the project financial gap in a greater percentage.

Moreover, CDM registration also alleviates the barriers faced by The Project **(Step 3. Barrier analysis)**.

A still depressive International Investment Climate towards emerging markets when The Project started construction (Barrier 1) that impeded funding is alleviated when CDM registration is achieved. When CDM registration is achieved the Sponsor could discount or borrow against CERs revenues at a low interest rate[54]. The Sponsor is currently evaluating this possibility to satisfy its own cash flow commitments.

Government policies pro-Camisea natural gas project and pro-natural gas based electricity generation (Barrier 2) will be alleviated. CERs revenues will allow The Project to better compete with more efficient technologies available in the country (open cycle and combined cycle Camisea-natural-gas-based

[49] As stated in a Sponsor's Board of Directors act signed as of April 2002 - made available to the DOE.
[50] International Emissions Trading Association and The World Bank Carbon Finance Business (Washington DC, May 2005) - State and Trends of Carbon Market 2005, Page 4.
[51] \$45.09 minus \$27.24.
[52] \$41.80 minus \$27.24, for a CERs revenues stream of 21 years.
[53]Delivery risk from 2005-2007, uncertainty related to technical aspects of the import of CERs into the EU ETS, among others. These and further explanations of the difference in EUA and CER prices are stated by: International Emissions Trading Association and The World Bank Carbon Finance Business (Washington DC, May 2005) - State and Trends of Carbon Market 2005, Page 4.
[54]Given that this revenue streams has CDM risk only.

electricity generation), and also to better manage the lower electricity market price-consequence of the incorporation of more efficient technologies to the system. The CERs revenue could also offset the fiscal incentives given by the Peruvian government to natural gas-fired power projects/plants (i.e. Selective Consumption Tax exemption for the gas).

Since the approval and registration of The Project as a CDM activity alleviate the economic and financial hurdles (Step 2) and other identified barriers (Step 3) to a reasonable extent, it is concluded that The Project is additional under Step 5.

Because all of the above steps were satisfied, the CDM Project activity is not the baseline scenario, meaning The Project is additional.

B.4. Description of how the definition of the project boundary related to the baseline methodology selected is applied to the project activity:

The only GHG included in the ER calculation is CO_2. The spatial extent of The Project boundary includes all power plants connected physically to the *SEIN*. As of today, no electricity exports or imports have occurred in the *SEIN* but will be monitored if any.
Although traditionally in The Project boundary, the main energy source had been hydropower, the exploitation of natural gas deposits of Camisea, has already started to mark a new stage in the use of energy in Peru. Natural gas will turn into the most attractive economic resource to generate electricity during the present and next decades. This change in the BLS will be monitored according to The Monitoring Plan.

B.5. Details of baseline information, including the date of completion of the baseline study and the name of person (s)/entity (ies) determining the baseline:

The baseline study was completed on 30/11/2004 by:
Senior Financial Specialist
Francisco Fernández-Asín
The NCDMF
Washington DC
USA.
The NCDMF is also a project participant listed in annex 1 of this document.

SECTION C. Duration of the project activity / Crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

01/11/2002 (DD/MM/YYYY)

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

40y-0m

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

The Project activity will use a renewable crediting period. Therefore only C.2.1 will be completed.

C.2.1. Renewable crediting period

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

01/04/2004 (DD/MM/YYYY)

C.2.1.2. Length of the first crediting period:

7y-0m

C.2.2. Fixed crediting period:

N/A

C.2.2.1. Starting date:

N/A

C.2.2.2. Length:

N/A

SECTION D. Application of a monitoring methodology and plan

D.1. Name and reference of approved monitoring methodology applied to the project activity:

“Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources (ACM0002)”

The above methodology is hereafter referred to as the “Monitoring Methodology”.

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

The Project is a grid-connected zero-emission renewable power generation activity and meets all the following conditions that are stated in the Monitoring Methodology (ACM0002):

- The Project supplies electricity capacity addition from hydropower source; it is a hydropower plant with existing reservoir where the volume of the reservoir is not increased.
- The Project is not an activity that involves switching from fossil fuels to renewable energy at The Project site;
- The electricity grid is clearly identified (as the *SEIN*) and information on the characteristics of the grid is available.

No leakages were identified and hence will not be monitored.

The following variables will be monitored as stipulated by the Monitoring Methodology:

- Electricity generation from The Project (double checking through quality control/assurance procedures).
- The latest *SEIN* grid data supplied by the *COES* is used for the calculation of the DDA-OM, and for the BM. Both margins are to be calculated ex-post annually based on the most recent statistics available as directed in the Monitoring Plan.

D.2. 1. Option 1: Monitoring of the emissions in the project scenario and the baseline scenario

D.2.1.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:								
ID number *(Please use numbers to ease cross-referencing to D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.1.2. Description of formulae used to estimate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

There are no project emissions.

D.2.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions by sources of GHGs within the project boundary and how such data will be collected and archived :								
ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? [55](electronic/ paper)	Comment

[55] Data should be archived for two years following the end of the crediting period

1. EGh	*Electricity supplied to the Grid by The Project*	*ENOSA or COES (when the Operator is an active member of COES)*	*MWh*	*Directly Measured*	*Hourly measurement and monthly recording*	*100%*	*electronic*	*Electricity supplied by The project activity to the grid. Double check with receipt of sales*
2. EFy	*CO_2 emission factor of the grid*	*Own production*	tCO_2e/MWh	*c*	*yearly*	*100%*	*electronic*	*Calculated as a weighted sum of the OM and BM emission factors*
3. EFomy	*CO_2 Operating Margin Emission Factor of the grid*	*Own production*	tCO_2e/MWh	*c*	*yearly*	*100%*	*electronic*	*Calculated as indicated in the relevant OM baseline method (DDA-OM)*

4. EFbmy	*CO_2 Build Margin emission factor of the grid*	*Own production*	*tCO_2e/MWh*	*c*	*yearly*	*100%*	*electronic*	*Calculated as Sum(Fi,y*COEF)/Sum(Gen m,y) over recently built power plants defined in the baseline methodology (BM2)*
5. F i,y	*Amount of each fossil fuel consumed by each power source/plant*	*Own production by using COES Net efficiency conversions (NECs) annual data**	*TJ*	*e*	*monthly*	*100%*	*electronic*	*Reliably estimated with the Annual Plant Fuel Requirement (APFR) Formula[56]: Gen (KWh)*3.6*10^6/(NEC*10^12)=TJ, where Net efficiency conversions ("NECs") are the average real NECs per technology. Real NECs per power plant need to be taken from most recent COES annual Statistics. The monitoring of parameter 5 should be done monthly but at the end of the year NECs per technology should be replaced by using the most recent year published NECs information, accordingly. *COES monitors fuel consumption by calculating it from electricity produced and real NECs per power plant. This is the same approach that will be used to monitor Parameter 5 in The Project's MP.*

[56] The APFR Formula has been taken from The Green House Assessment Handbook (September, 1998) – a World Bank document.

6. COEFi	*CO_2 emission coefficient of each fuel type i*	*Own production*	*tCO_2e/mass or volume unit*	*c*	*yearly*	*100%*	*electronic*	*COEFs need to be updated annually with annual Real NECs data, published by COES. Average COEFs per technology will need to be calculated separately by the ERCP Manager by using the average Real NECs per technology, which are to be calculated separately as well. The COEF formula to use is the following: COEFs per technology = [3.6 x (44/12) x C x O] / [10^3 x NEC average per technology]-This formula is deducted from the APFR formula*
7. Gen	*Hourly electricity generation of all units f the grid*	*COES*	*MWh*	*m*	*Hourly measured by monthly recording*	*100%*	*electronic*	*Should be taken from COES.*
8. Plant Name	*Identification of power plants for the OM*	*COES*	*Text*	*e*	*yearly*	*100% of set plants*	*electronic*	*Identification of plants to calculate OM*
9. Plant Name	*Identification of power plants for the BM*	*COES*	*Text*	*e*	*yearly*	*100% of set of plants*	*electronic*	*Identification of plants (m) to calculate BM*
11.	*The merit order in which power plants are dispatched by documented evidence*	*COES*	*Text*	*m*	*Weakly*	*100%*	*Paper for original documents, else electronic*	*Required to stack the plants in the dispatch data analysis*

11a. GENimports	*Electricity imports to The Project's electricity system*	*COES*	*KWh*	*c*	*yearly*	*100%*	*electronic*	*Obtained from the latest local statistics. If local statistics are not available, IEA statistics are used to determine imports. Imports are not expected but will be monitored if any*
11.b. COEFimports	*CO_2 emission coefficient of fuels used in connected electricity systems (if imports occur)*	*COES*	*tCO_2e/mass or unit volume*	*c*	*yearly*	*100%*	*electronic*	*Obtained from the latest local statistics. If local statistics are not available, IPCC default values are used to calculate them*

Baseline Emission Parameters numbering use ID numbers defined in the ACM0002 Methodology/Version 01's page 13 (http://cdm.unfccc.int/EB/Meetings/015/eb15repan2.pdf.).

D.2.1.4. Description of formulae used to estimate baseline emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

See Section E.4. for baseline emissions calculations.

D. 2.2. Option 2: Direct monitoring of emission reductions from the project activity (values should be consistent with those in section E).

D.2.2.1. Data to be collected in order to monitor emissions from the project activity, and how this data will be archived:

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e),	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

D.2.2.2. Description of formulae used to calculate project emissions (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.):

N/A

D.2.3. Treatment of leakage in the monitoring plan

D.2.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project activity

ID number *(Please use numbers to ease cross-referencing to table D.3)*	Data variable	Source of data	Data unit	Measured (m), calculated (c) or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

N/A

D.2.3.2. Description of formulae used to estimate leakage (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

N/A

D.2.4. Description of formulae used to estimate emission reductions for the project activity (for each gas, source, formulae/algorithm, emissions units of CO_2 equ.)

N/A

D.3. Quality control (QC) and quality assurance (QA) procedures are being undertaken for data monitored

Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
1	*Low*	*Sales record to the grid (COES) or final client (ENOSA) and other records are used to ensure consistency*
Others	*Low*	*IEA statistics (for energy data) are used to check local data*

D.4 Please describe the operational and management structure that the project operator will implement in order to monitor emission reductions and any leakage effects, generated by the project activity

No especial monitoring equipment is needed. The NCDMF will provide SINERSA with a Monitoring Plan and pre-programmed spreadsheets so The Project sponsor will just need to collect the information as described and apply the formulas as directed in the Monitoring Plan. The collection sources of the data will not be in any case the Project own records but the final client records of hourly production to keep the highest transparency and accuracy of the data. When The Project Operator is an active member of *COES* the Project generation data will come from *COES*. The Project Staff designated will confirm these data with own records and own records will be double checked with sales receipts.

D.5 Name of person/entity determining the monitoring methodology:

The Monitoring Methodology and Monitoring Plan were completed on 30/11/2004 by:
Senior Financial Specialist
Francisco Fernández-Asín
The NCDMF
Washington DC
USA.
The NCDMF is also a project participant listed in annex 1 of this document.

SECTION E. Estimation of GHG emissions by sources

E.1. Estimate of GHG emissions by sources:

The Project shall be responsible for zero GHG emissions. Hydropower plants built over existing reservoirs where the volume of the reservoir is not increased are classed as zero emission projects and there are no associated emissions in The Project boundary.

E.2. Estimated leakage:

The Project is not responsible for any leakage.

E.3. The sum of E.1 and E.2 representing the project activity emissions:

The Project is not responsible for any project activity emissions. Project activity emissions are zero (0) because there are no anthropogenic emissions or leakage.

E.4. Estimated anthropogenic emissions by sources of greenhouse gases of the baseline:

The Methodology stipulates that the Baseline of The Project is the Combined Margin emission factor (CM), which is the average of the Operating Margin emission factor (OM) and the Build Margin emission factor (BM). Estimated anthropogenic emissions were calculated for The Project following a 4-step-process:

Step 1 – Calculation of the Operating Margin emission factor (OM)
Step 2 – Calculation of the Build Margin emission factor (BM)
Step 3 – Calculation of the Baseline emission factor (CM)
Step 4 – Calculation of The Project's Emissions Reductions Prior to Validation

Step 1 – Calculation of the Operating Margin emission factor

Out of four options for the OM, the Dispatch Data Analysis Operating Margin Emission Factor (DDA-OM) was taken; as it constitutes the first methodological choice where data is available, according to The Methodology.

The formula for the DDA-OM used was provided by The Methodology:
EF_OMy Dispatch Data (tCO_2e/MWh)= E_OMy/EGy
E_OMy = Sum of [average tCO_2e/MWh emitted by plants that fall within top 10% of grid dispatch each hour of the year "times" The Project generation in MWh each hour of the year]
EGy = The Project Generation in the year

For this calculation the BLS used the units' hourly generation of 2003, which was the most recent statistic data available. Because at the time the BLS was completed, The Project hourly generation data for a whole year was inexistent, it was assumed that The Project operated at full capacity and dispatched equally during all hours of the year.

Considering this assumption, the variables were defined as follows:
-EGy: An "approximation" to MWh generated in 2003 by The Project - was obtained from multiplying Installed Capacity (MWh) of The Project times 8760.
-EGh: An "approximation" to MWh generated in each hour of 2003 - assumes that The Project produces at its full installed capacity (15.2MWh) each hour.
-Fi,n,h: Electricity output in MWh hourly produced in 2003 by each unit of the *SEIN* that fall within the top 10% of grid dispatch.

-COEFi,n[57]: The tCO_2e/MWh factors assigned to each unit of the *SEIN* according to its technology – For hydropower plants the COEF = 0.

The information of the hourly generation of all *SEIN* units and their COEF associated was organized in columns (in EXCEL), where the position of the columns was sorted according to a "monthly grid dispatch merit order" calculated[58]. This organization helped to identify the plants that fall within top 10% of grid dispatch each hour of the year.

The BLS's resulting Dispatch Data Analysis Operating Margin emission factor was **0.72614 tCO_2e/MWh** and was obtained from dividing E_OMy by EGy =96,688/133,152.

E_OMy:	**SUM Egh*EF_DDh**	96,688	133,152	**:EGy**
EOMy/Egy:	**Operating Margin**	**DDA_OM**	**0.72614**	**:EF_OMy DD (TCO2/MWh)**

Source: Own production

Step 2 – Calculation of the Build Margin emission factor

According to the Methodology, the BM is defined as the generation-weighted average emission factor of either the 5 most recent or the most recent 20% of power plants built (in generation), whichever group's annual generation is greater. Both lists of plants should exclude CDM-Status Plants[59]. Out of the 2 options for the BM, option 2 was selected for the sake of conservativeness; this option does not include in-construction plants in the samples and requires an annual ex-post calculation for the first crediting period. The formula applied to the selected sample was:

EF_BMy (tCO_2e/MWh) = [∑I,m Fi,m,y,*COEFi,m] / [∑mGENm,y]
F=Generation of each plant of the selected sample
COEF=tCO_2e/MWh of each plant of the selected sample;
GEN=Generation of each plant of the selected sample

In the BLS, any increase in installed capacity in the *SEIN* was identified and considered only if the increase was made in new units added (No: upgrades, rehabilitations or interconnections of old units). The following list shows the capacity additions (new units') in the *SEIN* from 1988 to 2003, and their annual generation. As The Project did not generate yet, the annual generation of the additions taken was the average of their three most recent year's generations.

Classification of SEIN Addition in Installed Capacity (MW)

Newly Built =	Only when new units are added - interconnection of units less than 5 years old are included
Interconnection =	Old unit that gets interconnected to SEIN
Rehabilitation =	Reconstruction of a plant that was broken down
Upgrade =	Same unit that increases its installed capacity by technological improvements or adjustments

Source: Own production

[57] COEFs assigned to each unit of the *SEIN* according to their technology can be seen in Annex 3 using IPCC 1996 values.
[58] This was done by a simple average of the four weekly Santa Rosa Equivalent Cost Soles/MWh (merit orders) assigned to each unit of the *SEIN*, by *COES*, in a month.
[59] The Project is currently the only CDM-Status Plant of the *SEIN*.

Generation of Additions to the *SEIN* (1988-2003)[60]

Years	Techn	Addition Category	Install.Cap. Added (MW)	2001 Gen (GWh)	2002 Gen (GWh)	2003 Gen (GWh)	Annual Generation (GWh)
1988							
C.H. CARHUAQUERO	HYDRO	Newly built	75.1	469.27	479.41	458.78	**469.16**
CHARCANI (I-V)	HYDRO	Newly built	136.80	842.17	641.80	660.24	**714.74**
1993							
TG VENTANILLA 2	D2	Newly built	100	2.40	2.45	1.54	**2.13**
TG VENTANILLA 1	D2	Newly built	100	2.40	2.45	1.54	**2.13**
1995							
CALANA	R6	Newly built	19.2	33.02	25.72	45.81	**34.85**
1996							
STA. ROSA WESTING	D2	Newly built	127.7	9.41	5.61	11.60	**8.88**
1997							
C.H. GALLITO CIEGO	HYDRO	Newly built	34.0	183.53	149.71	121.79	**151.68**
TG VENTANILLA	D2	Newly built	184.0	4.41	4.51	2.83	**3.92**
MOLLENDO MIRLESS	R500	Newly built	31.7	10.98	9.53	35.37	**18.63**
1998							
AGUAYTIA 1	GAS	Newly built	86.3	230.80	412.26	466.80	**369.95**
AGUAYTIA 2	GAS	Newly built	86.3	216.30	332.89	367.97	**305.72**
TG MALACAS	PM GAS	Newly built	102.2	206.23	181.35	274.30	**220.63**
1999							
SAN GABAN II	HYDRO	Newly built	55.0	357.38	376.19	356.34	**363.30**
CALANA	R6	Newly built	6.4	11.01	8.57	15.27	**11.62**
MOLLENDO TGM	D2	Newly built	90.0	0.73	0.86	1.43	**1.01**
2000							
SAN GABAN II	HYDRO	Newly built	58.1	377.51	397.38	376.41	**383.76**
ILO2 TVC	COAL	Newly built	145.0	338.78	845.93	859.44	**681.38**
C.H. CHIMAY	HYDRO	Newly built	156.0	724.76	752.96	825.87	**767.86**
C.H. YANANGO	HYDRO	Newly built	42.3	214.60	239.13	202.28	**218.67**
2001							
TUMBES	R6	Newly built	18.3	22.38	20.73	27.99	**24.36**
2002							
C.H. HUANCHOR	HYDRO	Newly built	18.9	-	36.86	144.64	**144.64**
2003							
YARINACOCHA	R6	Newly Built	25.6	-	-	56.88	**144.97**

Source: Own production

Out of the list above, it can be seen that the 5 most recently built plants up to 2003 were: 1)Yarinacocha, 2) Huanchor, 3)Tumbes, 4)Yanango and 5) Chimay, and their comprised annual generation was 1,300.5 GWh. Because the annual generation of the 20% most recently built was greater, 3,860.08 GWh, the latter group was selected for the BM calculation. The 20% most recently built plants[61], in generation, comprises the whole list above except for 1988 capacity additions in the *SEIN*.

Because the tCO_2e that each unit of the selected sample emits is a direct function of the technology it uses; **The selected sample of Newly Built plants was organized (clustered)** by technology and each technology's annual electricity generation output was transformed back to its fuel consumption caloric value through the Annual Plant Fuel Requirement formula[62] and multiplied by C x O[63] x 44/12 (mass conversion factor). The total tCO_2e per fuel type obtained was added up and the result was divided by the total generation (MWh) of the selected sample. Hence a weighted average tCO_2e/MWh of the selected sample was obtained.

The BLS' resulting BM2 was 0.36371 tCO_2e/MWh, and was obtained from dividing total tCO_2e emitted from the selected sample "by" total generation of the selected sample.

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[60] In the table, San Gaban appears twice because the increases on its installed capacity were 2 units, the first one was put in operation in 1999 and the second one in 2000 – each unit generation was considered accordingly.

[61] Exactly, the selected sample's generation comprises 19.69% (or 20% rounding to the nearest integer) of 2001-2003 average annual generation of the *SEIN* (19,603 GWh).

[62] APFR (TJ) = Gen(KWh)*3.6*10^6 / (NEC*10^12).

[63] C and O use IPCC-1996 world wide values per fuel type.

Technologies in Selected Sample	Most Recent Year Gen (GWh)	% per technology	APFR	C	O	44/12	CO2 Emissions(tCO2)
Coal	681.38	18%	7,433.28	25.80	0.980	3.67	689,124
d2	18.06	0%	186.12	20.20	0.990	3.67	13,647
r6	215.80	6%	1,807.54	21.10	0.990	3.67	138,445
r500	18.63	0%	204.82	21.10	0.990	3.67	15,688
Dry Gas	675.68	18%	7,484.40	15.30	0.995	3.67	417,776
Pure Methane Gas	220.63	6%	2,443.85	14.50	0.995	3.67	129,282
Dry Gas CC	0.00	0%	0.00	15.30	0.995	3.67	0
Hydro	2,029.91	53%	0.00	0.00	0.000	0.00	0
TOTAL	3,860.08	100%					1,403,961

BM2=	**0.36371**	**tCO2//MWh**

Source: Own production

Step 3 – Calculation of the Baseline emission factor

The Baseline Emission Factor was calculated as a combined margin (CM), consisting of the simple average[64] of both the resulting OM and the resulting BM. All margins are expressed in tCO_2e/MWh.

CM = 0.5*OM + 0.5*BM

CM = 0.5*(0.72614) + 0.5*(0.36371) = 0.54493 tCO_2e/MWh

The BLS's resulting Baseline Emission Factor was 0.54493 tCO_2e/MWh.

Step 4 – Calculation of The Project's Emissions Reductions Prior to Validation

Because The Project itself does not produce any emission, no leakages entered into the calculation of estimated ERs, and the baseline emissions were estimated to be equal to The Project ERs. The estimated ERs per year for The Project were obtained from the following multiplication:

Estimated Baseline Emissions = CM* (Estimated Annual Project Generation in MWh)

Estimated ERs per year = CM* (Estimated Annual Project Generation in MWh)

Estimated ERs per year = 0.54493 tCO_2e/MWh * 57,740 MWh = 31,463 tCO_2e or 31,463 ERs

Assuming the 3 most recent years (data used for the BSL calculations) were average years in hydrological conditions. The ERs per year estimated for the first crediting period are:

Estimated ERs for the first crediting period = 31,463 tCO_2e/yr* 7 yrs = 220,241 tCO_2e or Estimated ERs[65].

E.5. Difference between E.4 and E.3 representing the emission reductions of the project activity:

The ERs of The Project equal the baseline emissions because The Project itself does not produce any emission.

E.6. Table providing values obtained when applying formulae above:

Year	Total baseline emissions (tCO_2e)	Total Project emissions (tCO_2e)	ERs(tCO_2e)
2005	31,463	0	31,463
2006	31,463	0	31,463
2007	31,463	0	31,463
2008	31,463	0	31,463
2009	31,463	0	31,463
2010	31,463	0	31,463
2011	31,463	0	31,463
Total	**220,241**	**0**	**220,241**

[64] The default weights (50%,50%) were kept.

[65] All margins were rounded to the fifth decimal, but the CERs per year was rounded down to the nearest integer. The exact generation herewith considered is 57,739.5 MWh/yr, this generation does not need to be rounded down to the nearest integer.

SECTION F. Environmental impacts

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

An EIA was a legal requirement for The Project. Electric Concessions Law ("ECL")'s Article 25 lists the EIA as a requirement to obtain a definitive concession from the *MINEM*. The Project needed a definitive concession to be granted by the *MINEM*[66], because it attained the construction and operation of an electricity generation activity of more than 10 MW of installed capacity.

Numerous environmental assessment documents were completed during preparation of The Project. An EIA was completed for the hydropower project specifically, which analyzed impacts during construction and operation. In part due to the highly intervened surroundings, no major impacts were identified. Construction impacts were well managed through proper environmental practices, as enumerated in an Environmental Management Plan submitted and approved by IDB, DEG and The World Bank - all financiers involved in the Project. A separate EIA was completed for the transmission line, with, again, no major impacts identified.

Communities along the transmission line were given the opportunity to connect to the line. The Project has lately installed a 22.9 KV keys yard to feed 3 small isolated systems: The Lancones system, The Chira system, and a third one that goes into a small population located close to the Ecuadorian border. These three small populations' consumptions will be partly "subsidized" by the Peruvian Government according to The Department of Energy and Mines overall initiative regarding social development and rural electrification: *FOSE*[67] and Rural Electrification Plan, respectively.

Other direct beneficial effects resulting from The Project include:

-Supply of a clean source of energy;
-Training to locals on the adequate uses of electricity;
-Tax collections in the project area will boost the availability of funds for the development of local communities at an estimated annual average of 500,000 USD;
-Creation of more than 200 jobs during the construction phase, employing exclusively locals impacting positively more than 200 families;
-Contribution to the domestic capacity building efforts in environmentally sound technologies (EST) promoting the participation of local companies in the project activity including the manufacturing, for the first time in Peru, of Kaplan turbines.
-Creation of around 30 permanent positions for the operation of the hydroelectric plant transferring know how in operation, maintenance and control of hydroelectric equipment and systems. These positions will utilize locally hired staff, who will be trained during the construction phase;
-Development of the poorest zones of the country, which using electricity will have the opportunity to start productive activities. Initially these will be promoted through the maximum use of local supplies;
-First project in the Ecuadorian - Peruvian border, which will serve as a good reference projects for future initiatives for the sustainable development of this area with low human development indexes (HDI);
-Mitigate the migration of peasants to the coastal cities of Peru;
-SINERSA has expressed its commitment to education and local technical training;

[66] Articles 3 and 24 of ECL define in which cases "a concession" and "a definitive concession" are required, respectively.
[67] *Fondo de Compensacion Social Electrica* – was created by Law 27510 in 2001. Currently FOSE's life is set until December 2006. The FOSE was created to favor electricity access and permanency of it to all clients that consume less than 1000 KWh., by providing them discounts

-Improvement and reduction of operating costs of the Poechos dam including the elimination of diesel based generators currently supplying electricity to the dam;
-Increase in direct investment in the Project's area of around 5 Million USD; and
-Increase in investment in Peru of nearly 16.5 Million USD

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

EIA report approval by Environmental Agency:
March 13, 2003 (project by CONAM)
March 31, 2003 (EIA by *MINEM*)
Other Permits: Water concession

Potential Environmental Impacts of The Project:

Environmental	Magnitude (High, Medium, Low)	Comments
Increased erosion	Low	No destruction of the local forest was caused, therefore this impact was minor.
Deterioration of the landscape	Low	All works are overshadowed by the existing civil works of the dam; therefore no deterioration of the landscape is expected.
Air emissions	Low High (+)	Very little impact caused only from the diesel generators to be used during construction. The Project will result in the reductions of local pollution and carbon emissions to the atmosphere, which will have a positive effect both locally and globally.
Loss of vegetation and biodiversity	Low	No impact, because the density within The Project area is low, and the river is highly intervened.
Loss of agricultural area	Low	The Project will not cause any loss of agricultural areas.
Lack of water for biological functions in the river	Low	Sponsor is working with authorities to ensure that the minimum ecological flow of 10 m3/s is maintained at all times.

Source: The Sponsor

SECTION G. Stakeholders' comments

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

As part of Environmental Impact Assessment guidelines and procedures by The Government of Peru and in full compliance with World Bank Safeguard Policies, several workshops with the local communities took place. Each EIA (power plant and transmission line) was consulted with affected groups, and were available for comment to NGOs through the environmental agency. The EIA for The Project was consulted in 1997 during the process of concessioning. Announcements were posted in local newspapers. The EIA for the transmission line was consulted publicly on July 23, 2003 in Sullana.

G.2. Summary of the comments received:

As part of the EIA process, local stakeholders were consulted. The summary EIA reports include a section on the public consultation process, wherein the groups consulted and their comments are detailed. The EIAs are available for public review at the Department of Energy and Mines (*MINEM*), and are

available locally. Local stakeholders' questions revolved around concerns from surrounding municipalities about the timing for the electrification of their villages.

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

Because no negative comments were received, The Project Developer outlined its own initiatives to continue with the community support of The Project. The following social priorities were undertaken during design, construction and will continue to be undertaken in The Project operation:

-Consolidate the good relationship with the locals and keep close communication with the community of Lancones;
-Hire and train local workers for construction and operation;
-Develop local technical capabilities;
-Maximum use of local products, supplies and materials for The Project;
-Contract Peruvian companies to perform the planned activities, including the manufacturing of the first Kaplan turbines to be made in Peru;
-Prioritize the target of the social investment with the community;
-Promote the improvement of the educational level;
-Address World Bank Safeguard Policies

In addition, and as a response to local stakeholders' comments, The Project has cooperated with an ambitious *MINEM*-initiative Rural Electrification Plan by creating three new "small electric systems" or sub-grids from the SINERSA's transmission lines. The impact of electricity supply in this underdeveloped area close to the border with Ecuador (and once considered a security zone) is instrumental for the area's development. The Governmental plan was possible by The Project's cooperation, and The Project's consideration of local stakeholders' concerns regarding local electrification.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	SINERSA
Street/P.O.Box:	Calle Los Ruisenhores Oeste 277, San Isidro, Lima
Building:	
City:	Lima
State/Region:	Lima
Postfix/ZIP:	
Country:	Peru
Telephone:	
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E-Mail:	
URL:	
Represented by:	
Title:	General Manager
Salutation:	Mr.
Last Name:	Zdravkovic
Middle Name:	
First Name:	Branislav
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Personal E-Mail:	

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E-Mail:	
URL:	
Represented by:	
Title:	Sr. Financial Specialist
Salutation:	Mr.
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Middle Name:	
First Name:	Francisco
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Mobile:	
Direct Fax	
Direct tel:	
Personal E-Mail:	

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

N/A

Annex 3

BASELINE INFORMATION
ABBREVIATIONS

APRF	Annual Plant Fuel Requirement (TJ)
Baseline emissions	Product of the EFy times EGy
BLS	Latest Baseline Study (2004)
BM	Build Margin Emission Factor
BM2	Build Margin Emission Factor – Option 2
C	Carbon Content (tC/TJ) Factor - 1996 IPCC worldwide values
CDM	Clean Development Mechanism
CERs	Certified Emission Reductions
CM	Combined Margin Emission Factor
COEF	tCO_2e/MWh
COES	Committee of Economical Operation of the *SEIN* (Dispatch Center)
DOE	Designated Operational Entity
DDA-OM	Dispatch Data Analysis Operating Margin Emission Factor
ECL	Peru's Electric Concessions Law of 1993 (Law 25844)
EFy	Baseline Emission Factor (tCO_2e/MWh)
EGy	The Project annual generation (MWh)
ENOSA	Electronoroeste S.A (The Project Final Client)
ERs	Green House Gases Emissions Reductions
GHG	Green House Gases
GWh	Gigawatts hours
HP	Hydropower plant (s)
HT	Heat Turbine
LRMC	Long Run Marginal Cost of the *SEIN*
Merit Order	Grid Dispatch Weekly Merit Order
MINEM	Peru's Department of Energy and Mines
Monthly Merit Order	Average of Four Weekly Grid Dispatch Merit Orders
MP	Monitoring Plan
MWh	Megawatts hours
NEC	Net Efficiency Conversion
O	Oxidation Factor - 1996 IPCC worldwide values
OM	Operating Margin Emission Factor
OSINERG	Peru's Energy Investment Supervisory Agency (Regulatory Entity)
PPA	Power Purchase Agreement
SEIN	National Electric Grid or National Interconnected Electric Grid
SINERSA	Sindicato Energetico S.A (The Project Developer and The Project Current Operator)
tCO_2e	Tons of carbon dioxide equivalent
The Operator	SINERSA (The Project Operator)
TP	Thermal fossil fuel-fired plant(s)

NECs & IPCC 1996 values per technology (C & 0) used for the ERs estimation

COEF(tCO2/MWh)	Open Cycle					
Type of Fuel	D2	R6	R500	Gas Dry	Gas PM	Coal
NEC	34.93%	42.98%	32.74%	32.50%	32.50%	33.00%
C Content	20.20	21.10	21.10	15.30	14.50	25.80
Oxidation Factor	0.99	0.99	0.99	0.995	0.995	0.98
COEF(tCO2/MWh)	**0.76**	**0.64**	**0.84**	**0.62**	**0.59**	**1.01**

COEF(tCO2/MWh)	Combined Cycle				
Type of Fuel	D2	R	Gas Dry	Gas PM	Coal
NEC	55.00%	55.00%	54.00%	55.00%	55.00%
C Content	20.20	21.10	15.30	14.50	25.80
Oxidation Factor	0.990	0.990	0.995	0.995	0.980
COEF(tCO2/MWh)	**0.48**	**0.50**	**0.37**	**0.35**	**0.61**

COEF(tCO2/MWh)	Cogeneration				
Type of Fuel	D2	R	Gas Dry	Gas PM	Coal
NEC	80%	80%	80%	80%	80%
C Content	20.20	21.10	15.30	14.50	25.80
Oxidation Factor	0.990	0.990	0.995	0.995	0.980
COEF(tCO2/MWh)	**0.33**	**0.34**	**0.25**	**0.24**	**0.42**

Source: Own production

NECs were calculated by assigning to each plant of the *SEIN* in first instance the NEC suggested by the World Bank Green House Assessment handbook and in second instance the NECs offered by current engines in the market – The values are specified in the following tables:

Net Efficiency Conversions suggested by WB GH Assessment Handbook

150 MW - 80% load factor-Coal fired Power Plant	Conventional Utility Scale-Gas Power Plant	Cogeneration
33.00%	32.50%	80.00%

Source: Green House Assessment Handbook, A Practical Guidance Document for the Assessment of Project-level Greenhouse Gas Emissions, September 1998 - pg. 24 -25

Net Efficiency Conversion per type of plant offered in the market.

Type of plant	Diesel Engine		Gas Turbine		Heat Turbine		Combined Cycle	
Type of Fuel	D2	R6	Gas	D2	R6	Coal	D2	Gas
Net Efficiency Conversion (%)	34%	43%	37%	36%	32%	37%	55%	54%

Source: Specification given by top-of-the-line engines offered in the market by: GE, Siemens, & other well-known manufacturers – 2003 survey used in previous Peru's BL calculation – It was considered that R6 NECs were similar to R500 NEC per technology – so the R500 class was not added in the table.

Then by clustering all plants by fuel type, an average NEC per fuel type for the *SEIN* (using the 2003 production of the plants as the weighting factor) was obtained as follow:

Efficiency Conversion per technology
Thermal plants

Thermal plants	TOTAL						Net Efficiency Conversion:		
Verdun ALCO9 (4)	0.000								
ILO 2 TV1	859.440	coal	33.00%	859.440	Tcoal		33.0%		
TG Santa Rosa UTI	5.008	d2	36%						
TG Santa Rosa BBC(1)	0.000	d2	36%						
TG Santa Rosa WTG	11.603	d2	36%						
GD Piura 2	0.464	d2	34%						
TG Piura	0.040	d2	36%						
GD Paita	0.852	d2	34%						
GD Sullana	2.299	d2	34%						
GD Chiclayo Oeste	9.215	d2	34%						
TG Trujillo	0.238	d2	34%						
TG Chimbote	0.491	d2	36%						
TG Ventanilla	5.910	d2	36%						
Cummins	0.604	d2	34%						
Mollendo TG1, TG2	1.428	d2	36%						
ILO CATKATO	0.155	d2	34%						
ILO TG1	0.117	d2	36%						
ILO TG2	0.086	d2	36%						
CT Moquegua	0.078	d2	34%						
CT Dolorespata	0.031	d2	34%						
CT Tintaya	1.747	d2	34%						
CT San Rafael (2)	0.000	d2	34%						
CT Bellavista	0.192	d2	34%						
CT Taparachi	2.656	d2	34%					Diesel Conversion	
Piura 1 Residual	15.023	d2	34%	62.589	TD2		34.93%	Efficiency	
Chilina D2	4.352	d2	36%						
Malacas	395.072	gas	32.50%			Dry Gas Co	32.50%		834.815
TGN4	341.020	gas	32.50%			Efficiency			
TG1	3.508	gas	32.50%			Pure Me. Gas Conversion			
TG2	12.408	gas	32.50%			Efficiency	32.50%		395.072
TG3	38.137	gas	32.50%						
TG1 Aguaytía	466.823	gas	32.50%	1,229.887	TGas				
TG2 Aguaytía (3)	367.991	gas	32.50%						
San Nicolás TV1	20.041	r500	32%						
San Nicolás TV2	4.419	r500	32%						
San Nicolás TV3	27.247	r500	32%						
CT Chilina	15.197	r500	37.5%						
Mollendo Mirrlees	35.382	r500	43.0%						
ILO TV1	51.463	r500	32%						
ILO TV2	92.533	r500	32%						
ILO TV3	153.153	r500	32%	640.949	Tr500		32.74%		
ILO TV4	241.513	r500	32%						
Yarinacocha (5)	56.882	r6	43.0%						
TV Trupal	0.271	r6	32.0%						
GD Pacasmayo	17.546	r6	43.0%						
Tumb-Mercedes-Zarum.	27.986	r6	43.0%						
CT Calana	61.085	r6	43.0%	163.770	Tr6		42.98%		

Source: Own production

***SEIN* Capacity Additions from 1988-2003 (all categories)**

Additions to SEIN	Situation	Additions in Installed Capacity (MW)
1988		
C.H. CARHUAQUERO	Newly built	75.1
CHARCANI (I-V)	Newly built	136.8
1993		
TG VENTANILLA 2	Newly built	100.0
TG VENTANILLA 1	Newly built	100.0
1995		
CALANA	Newly built	19.2
1996		
WESTINGHOUSE	Newly built	127.7
1997		
C.H. PARIAC	Interconnection	5.2
GD PACASMAYO	Interconnection	10.1
C.H. GALLITO CIEGO	Newly built	34.0
TG MALACAS	Interconnection	45.0
GD CHICLAYO OESTE	Interconnection	9.3
CH YAUPI	Interconnection	108.0
CH OROYA	Interconnection	21.3
CH MALPASO	Interconnection	54.4
TG VENTANILLA	Newly built	184.0
TV SAN NICOLAS	Interconnection	63.6
MOLLENDO MIRLESS	Newly built	31.7
ILO (TV1)	Interconnection	154.0
ILO TG	Interconnection	81.7
ILO (CATKATO)	Interconnection	3.3
1998		
AGUAYTIA 1	Newly built	86.3
AGUAYTIA 2	Newly built	86.3
C.H. CARHUAQUERO	Upgrade	19.9
GD SULLANA	Upgrade	3.2
TV TRUPAL	Upgrade	6.8
CHARCANI (I-V)	Upgrade	8.1
HERCCA	Interconnection	1.0
SAN RAFAEL	Interconnection	11.2
MOQUEGUA	Interconnection	1.0
TG MALACAS	Newly built	102.2
1999		
SAN GABAN II	Newly built	55.0
C.H. GALLITO CIEGO	Upgrade	4.1
C.H. CAHUA	Upgrade	1.6
CALANA	Newly built	6.4
GD PACASMAYO	Interconnection	14.5
C.H. CALLAHUANCA	Upgrade	3.3
GD PAITA	Upgrade	2.8
GD SULLANA	Upgrade	1.3
C.H. MATUCANA	Upgrade	8.6
MOLLENDO TGM	Newly built	90.0
2000		
SAN GABAN II	Newly built	58.1
ILO2 TVC	Newly built	145.0
C.H. MOYOPAMPA	Upgrade	24.6
C.H. CAÑON DEL PATO	Upgrade	92.7
C.H. CHIMAY	Newly built	156.0
C.H. YANANGO	Newly built	42.3
2001		
C.H. CANON DEL PATO	Upgrade	10.0
TUMBES	Newly built	18.3
MACHUPICCHU	Rehabilitation	92.3
SAN NICOLAS CUMMINS	Interconnection	1.3
2002		
C.H. CANON DEL PATO	Upgrade	4.2
C.H. HUANCHOR	Newly built	18.9
2003		
YARINACOCHA	Newly Built	25.6
ARCATA	Interconnection	5.1

Source: *COES* annual statistics for installed capacity, category validated with Energy experts.

Installed capacity per power plant of the *SEIN*, as of December 31st, for 1996-2003

1996

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
CAHUA S.A.	
C.H. CAHUA	41.5
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	120.0
C.H. CALLAHUANCA	71.0
C.H. MOYOPAMPA	63.6
C.H. HUAMPANI	31.4
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
EGENOR S.A.	
C.H. CAÑON DEL PATO	153.9
C.H. CARHUAQUERO	75.1
TG CHIMBOTE	63.4
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	26.3
GD CHICLAYO	17.3
GD PAITA	8.3
GD SULLANA	8.0
TV TRUPAL	12.0
ELECTROPERU	
C.H. MANTARO	798.0
C.H. RESTITUCION	210.4
ETEVENSA	
TG VENTANILLA	200.0
EGASA	
CHARCANI (I-V)	165.16
CHILINA TV	22
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
MACHUPICCHU	109.90
DOLORESPATA	15.62
BELLAVISTA	8.60
TAPARACHI	6.60
EGESUR	
ARICOTA I, II	35.70
CALANA	19.20
PARA	2.50

1997

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
CAHUA S.A.	
C.H. CAHUA	41.5
C.H. PARIAC	5.2
CNP ENERGIA S.A.	
GD PACASMAYO	10.1
C.H. GALLITO CIEGO	34.0
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	120.0
C.H. CALLAHUANCA	71.0
C.H. MOYOPAMPA	63.0
C.H. HUAMPANI	31.4
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
TG MALACAS	36.0
EGENOR S.A.	
C.H. CAÑON DEL PATO	153.9
C.H. CARHUAQUERO	75.1
TG CHIMBOTE	63.4
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	26.3
GD CHICLAYO OESTE	21.0
CHICLAYO NORTE	7.5
GD PAITA	8.3
GD SULLANA	8.0
TV TRUPAL	12.0
ELECTROANDES S.A.	
CH YAUPI	108.0
CH OROYA	9.0
CH PACHACHACA	12.0
CH MALPASO	54.4
ELECTROPERU	
C.H. MANTARO	798.0
C.H. RESTITUCION	210.4
ETEVENSA	
TG VENTANILLA	519.2
SHOUGESA	
TV SAN NICOLAS	62.5
EGASA	
CHARCANI I	168.82
MOLLENDO MIRLESS	32.09
CHILINA TV	22
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
MACHUPICCHU	109.90
DOLORESPATA	15.62
BELLAVISTA	7.83
TAPARACHI	7.80
EGESUR	
ARICOTA I, II	35.70
CALANA	19.20
PARA	2.50
ENERSUR	
ILO (TV1)	176.00
ILO TG	81.69
ILO (CATKATO)	3.30

Source: *COES.*

Continue: Installed capacity per power plant of the *SEIN*, as of December 31st, for 1996-2003

1998

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
AGUAYTIA 1	101.3
AGUAYTIA 2	101.3
CAHUA S.A.	
C.H. CAHUA	41.5
C.H. PARIAC	5.2
CNP ENERGIA S.A.	
GD PACASMAYO	10.1
C.H. GALLITO CIEGO	34.0
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	120.0
C.H. CALLAHUANCA	71.0
C.H. MOYOPAMPA	63.0
C.H. HUAMPANI	31.4
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
TG MALACAS	**147.2**
VERDUN	2.2
EGENOR S.A.	
C.H. CAÑON DEL PATO	153.9
C.H. CARHUAQUERO	95.0
TG CHIMBOTE	63.4
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	26.3
GD CHICLAYO OESTE	25.3
GD PAITA	8.3
GD SULLANA	11.2
TV TRUPAL	18.8
ELECTROANDES S.A.	
CH YAUPI	108.0
CH OROYA	9.0
CH PACHACHACA	12.0
CH MALPASO	54.4
ELECTROPERU	
C.H. MANTARO	798.0
C.H. RESTITUCION	210.4
ETEVENSA	
TG VENTANILLA	561.6
SHOUGESA	
TV SAN NICOLAS	**62.50**
EGASA	
CHARCANI I	**176.89**
MOLLENDO MIRLESS	31.7
CHILINA TV	22
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
HERCCA	**1.02**
DOLORESPATA	15.62
TINTAYA	17.96
BELLAVISTA	8.60
SAN RAFAEL	**11.16**
TAPARACHI	8.80
EGESUR	
ARICOTA I	35.70
CALANA	19.20
MOQUEGUA	1.00
PARA	2.50
ENERSUR	
ILO (TV1)	176.00
ILO TG	79.29
ILO (CATKATO)	3.30

1999

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
AGUAYTIA 1	86.29
AGUAYTIA 2	86.29
CAHUA S.A.	
C.H. CAHUA	**43.1**
C.H. PARIAC	5.2
CNP ENERGIA S.A.	
GD PACASMAYO	24.8
C.H. GALLITO CIEGO	**38.1**
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	**128.6**
C.H. CALLAHUANCA	**74.3**
C.H. MOYOPAMPA	64.7
C.H. HUAMPANI	30.2
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
TG MALACAS	147.2
VERDUN	2.3
EGENOR S.A.	
C.H. CAÑON DEL PATO	153.9
C.H. CARHUAQUERO	95
TG CHIMBOTE	63.8
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	26.3
GD CHICLAYO OESTE	**26.61**
GD PAITA	**11.1**
GD SULLANA	**12.5**
TV TRUPAL	15
ELECTROANDES S.A.	
CH YAUPI	108
CH OROYA	9
CH PACHACHACA	12.3
CH MALPASO	54.4
ELECTROPERU	
C.H. MANTARO	798
C.H. RESTITUCION	210.4
ETEVENSA	
TG VENTANILLA	549.3
SHOUGESA	
TV SAN NICOLAS	63.586
EGASA	
CHARCANI	176.89
MOLLENDO MIRLESS	31.71
MOLLENDO TGM	**90**
CHILINA TV	22
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
HERCA	1.02
DOLORESPATA	15.62
SAN GABAN	
SAN GABAN II	**55**
TINTAYA	17.96
BELLAVISTA	8.6
SAN RAFAEL	11.16
TAPARACHI	8.8
EGESUR	
ARICOTA	35.7
CALANA	**25.6**
MOQUEGUA	1
PARA	2.5
ENERSUR	
ILO 1	176
ILO 1 TG	79.29
ILO 1 CATKATO	3.3

Source: *COES.*

Continue: Installed capacity per power plant of the *SEIN*, as of December 31st, for 1996-2003

2000

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
AGUAYTIA 1	86.294
AGUAYTIA 2	86.294
CAHUA S.A.	
C.H. CAHUA	43.6
C.H. PARIAC	5.216
CNP ENERGIA S.A.	
GD PACASMAYO	24.562
C.H. GALLITO CIEGO	38.147
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	128.578
C.H. CALLAHUANCA	75.059
C.H. MOYOPAMPA	**89.25**
C.H. HUAMPANI	31.36
C.H. YANANGO	**42.3**
C.H. CHIMAY	**156**
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
TG MALACAS	141.296
VERDUN	2.319
EGENOR S.A.	
C.H. CAÑON DEL PATO	**246.582**
C.H. CARHUAQUERO	95.02
TG CHIMBOTE	63.833
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	26.715
GD CHICLAYO OESTE	26.61
GD PAITA	11.112
GD SULLANA	12.5
TV TRUPAL	15
ELECTROANDES S.A.	
CH YAUPI	108
CH OROYA	9
CH PACHACHACA	12.282
CH MALPASO	54.4
ELECTROPERU	
C.H. MANTARO	798
C.H. RESTITUCION	210.4
ETEVENSA	
TG VENTANILLA	549.316
SHOUGESA	
TV SAN NICOLAS	63.586
EGASA	
CHARCANI	176.89
MOLLENDO MIRLESS	31.71
MOLLENDO TGM	90
CHILINA TV	18
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
HERCA	1.02
DOLORESPATA	15.62
SAN GABAN	
SAN GABAN II	110
TINTAYA	17.96
BELLAVISTA	8.6
SAN RAFAEL	11.16
TAPARACHI	8.8
EGESUR	
ARICOTA	35.7
CALANA	25.6
MOQUEGUA	1
ENERSUR	
ILO 1	154
ILO 1 TG	81.69
ILO 1 CATKATO	3.3
ILO2 TVC	135

2001

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
AGUAYTIA 1	86.294
AGUAYTIA 2	86.294
CAHUA S.A.	
C.H. CAHUA	43.6
C.H. PARIAC	5.216
CNP ENERGIA S.A.	
GD PACASMAYO	**24.591**
C.H. GALLITO CIEGO	38.147
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	128.578
C.H. CALLAHUANCA	75.059
C.H. MOYOPAMPA	89.25
C.H. HUAMPANI	31.36
C.H. YANANGO	42.3
C.H. CHIMAY	156
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
TG MALACAS	173.2
VERDUN	2.319
EGENOR S.A.	
C.H. CAÑON DEL PATO	**256.55**
C.H. CARHUAQUERO	95.02
TG CHIMBOTE	63.833
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	27.277
GD CHICLAYO OESTE	26.61
GD PAITA	11.112
GD SULLANA	12.5
TV TRUPAL	15
ELECTROANDES S.A.	
CH YAUPI	108
CH OROYA	9
CH PACHACHACA	12.282
CH MALPASO	54.4
ELECTROPERU	
C.H. MANTARO	798
C.H. RESTITUCION	210.4
TUMBES	**18.339**
ETEVENSA	
TG VENTANILLA	384
SHOUGESA	
TV SAN NICOLAS	63.586
SAN NICOLAS CUMMINS	**1.25**
EGASA	
CHARCANI	176.89
MOLLENDO MIRLESS	31.71
MOLLENDO TGM	90
CHILINA TV	18
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
HERCA	1.02
MACHUPICCHU	**92.25**
DOLORESPATA	15.62
SAN GABAN	
SAN GABAN II	112.9
TINTAYA	17.96
BELLAVISTA	8.6
SAN RAFAEL	11.16
TAPARACHI	8.8
EGESUR	
ARICOTA	35.7
CALANA	25.6
MOQUEGUA	1
ENERSUR	
ILO 1	154
ILO 1 TG	81.69
ILO 1 CATKATO	3.3
ILO2 TVC	145

Source: *COES.*

Continue: Installed capacity per power plant of the *SEIN*, as of December 31st, for 1996-2003

2002

PLANT	INSTALLED CAPACITY (MW)
AGUAYTIA ENERGY S.A.	
AGUAYTIA 1	86.294
AGUAYTIA 2	86.294
CAHUA S.A.	
C.H. CAHUA	43.6
C.H. PARIAC	5.216
CNP ENERGIA S.A.	
GD PACASMAYO	**24.545**
C.H. GALLITO CIEGO	38.147
EDEGEL	
C.H. HUINCO	258.4
C.H. MATUCANA	128.578
C.H. CALLAHUANCA	75.059
C.H. MOYOPAMPA	89.25
C.H. HUAMPANI	31.6
C.H. YANANGO	42.3
C.H. CHIMAY	156
C.H. HUANCHOR	**18.86**
TG STA. ROSA WESTINGHOUSE	127.7
TG STA. ROSA UTI	109.8
TG STA. ROSA BBC	52.2
EEPSA	
TG MALACAS	**173.2**
VERDUN	1.001
EGENOR S.A.	
C.H. CAÑON DEL PATO	**260.73**
C.H. CARHUAQUERO	95.02
TG CHIMBOTE	63.833
TG PIURA	24.3
TG TRUJILLO	22.8
GD PIURA	27.85
GD CHICLAYO OESTE	26.61
GD PAITA	11.12
GD SULLANA	12.5
TV TRUPAL	15
ELECTROANDES S.A.	
CH YAUPI	108
CH OROYA	9
CH PACHACHACA	12.282
CH MALPASO	54.4
ELECTROPERU	
C.H. MANTARO	798
C.H. RESTITUCION	210.4
TUMBES	18.339
ETEVENSA	
TG VENTANILLA	384
SHOUGESA	
TV SAN NICOLAS	63.586
SAN NICOLAS CUMMINS	1.25
EGASA	
CHARCANI	176.89
MOLLENDO MIRLESS	31.71
MOLLENDO TGM	90
CHILINA TV	18
CHILINA CC	20
CHILINA SULZER	10.4
EGEMSA	
HERCA	1.02
MACHUPICCHU	92.25
DOLORESPATA	15.62
SAN GABAN	
SAN GABAN II	112.9
TINTAYA	17.96
BELLAVISTA	8.6
SAN RAFAEL	11.16
TAPARACHI	8.8
EGESUR	
ARICOTA	35.7
CALANA	25.6
MOQUEGUA	1
ENERSUR	
ILO 1	154
ILO 1 TG	81.69
ILO 1 CATKATO	3.3
ILO2 TVC	145

2003

PLANT	INSTALLED CAPACITY (MW)
TERMOSELVA	
AGUAYTIA 1	86.294
AGUAYTIA 2	86.294
CAHUA S.A.	
CAHUA	43.600
PARIAC	5.216
E. PACASMAYO	
PACASMAYO	24.617
GALLITO CIEGO	38.147
ARCATA	**5.098**
EDEGEL	
HUINCO	258.400
MATUCANA	128.578
CALLAHUANCA	75.059
MOYOPAMPA	89.250
HUAMPANI	31.360
YANANGO	42.300
CHIMAY	156.000
HUANCHOR	18.860
SANTA ROSA WTG	127.700
SANTA ROSA UTI	109.800
EEPSA	
MALACAS	**173.2**
EGENOR	
CAÑON DEL PATO	260.730
CARHUAQUERO	95.020
CHIMBOTE	63.833
TG PIURA	24.300
TRUJILLO	22.800
PIURA	27.850
CHICLAYO OESTE	26.610
PAITA	11.112
SULLANA	12.500
TRUPAL	15.000
ELECTROANDES	
YAUPI	108.000
OROYA	9.000
PACHACHACA	12.282
MALPASO	54.400
ELECTROPERU	
COMPLEJO MANTARO - MANTARO	798.000
COMPLEJO MANTARO-RESTITUCION	210.400
TUMBES	18.244
YARINACOCHA	**25.600**
ETEVENSA	
VENTANILLA	384
SHOUGESA	
SAN NICOLAS TV 1-2-3	**63.586**
SAN NICOLAS CUMNIS	**1.25**
EGASA	
CHARCANI	176.890
MOLLENDO MIRLESS	31.710
MOLLENDO TGM	90.000
CHILINA TV	18.000
CHILINA C.C	20.000
CHILINA SULZER	10.400
EGEMSA	
HERCA	1.020
MACHUPICCHU	92.250
DOLORESPATA	15.620
SAN GABAN	
SAN GABAN II	113.098
TINTAYA	17.960
BELLAVISTA	8.600
TAPARACHI	8.800
EGESUR	
ARICOTA	35.7
CALANA	25.6
MOQUEGUA	1
ENERSUR	
ILO 1 TV	154.000
ILO 1 TG	81.690
ILO 1 CATKATO	3.300
ILO 2 TVC1	145.000

Source: *COES.*

Detail of LRMC variables

In detail,

I_i: Sum of Equivalent Annual Costs of the New Capacity Investments ($ millions) for year i. Parameters considered for each Annuity were:
14% discount rate; expected life of thermal plants = 30 years; expected life of hydroelectric plants=40 years; depreciation method: sinking fund

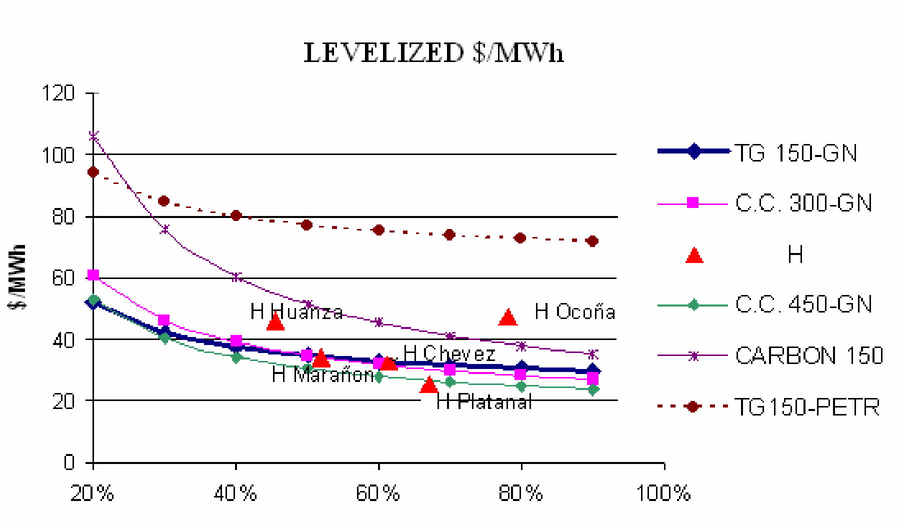
The Investment Cost considers:

a) Additional generation plants that start operations in years 2007-2017. Plants to be built are to use the most attractive technology for generation available in the market, natural gas. Their size and technological characteristics were determined by the WASP Program (Wien Automatic System Planning Package). WASP selects sequence of possible projects with the target of minimizing levelized costs. Within the candidate projects to be selected by WASP were gas based, oil based, carbon based and hydro based power projects. The restriction is that the projects cover the *SEIN* demand.

Alternatives Technologies chosen by the WASP Optimization Model

Alternative	Unit name	Observations
GT 100 MW	G100	O.C GT 100 MW NG Outside Lima - Camisea NG
GT 150 MW	G150	O.C GT 150 MW NG Outside Lima - Camisea NG
CC 2 GT 100+1 HT 100	CC300	CC 300 MW -NG 2 GT of 100 MW - Camisea NG 1 HT of 100 MW - Camisea NG
CC 2 GT 150 + 1 HT 150	CC450	CC 450 MW –NG 2 GT of 150 MW - Camisea NG 1 HTof 150 MW - Camisea NG

Source: Peru's Sectoral Baseline Study (2003).



Load Factors

Source: Peru's Sectoral Baseline Study (2003).

The WASP generates sequences of projects that comply with the limit values for maximum and minimum reserves, and maximum number of units of the alternatives given.

The WASP determines also the O&M Cost as a function of the hydro supply and *SEIN* demand for each year in question (2007-2017)

b) Prices of gas turbines – were based on publications in the magazine World Gas Turbine and Installation costs were based on Electroperu and *MINEM* estimations

c) *SEIN* Interconnection costs - elevator transformers (keys yard), 1 exit substation, a short transmission line, and transmission-line-interconnection cells.

Natural Gas-fired plants Investment Costs Considered

Alternative	Code	Power (MW)	Total ($000)
GT 100 MW	G100	368	36,790
GT 150 MW	G150	336	50,457
CC 2 GT 100+1 HT 100	CC300	475	142,376
CC 2 GT 150 + 1 HT 150	CC450	434	195,267

Source: Peru's Sectoral Baseline Study 2003.

The WASP results for capacity additions were the following:

Additional Generation Plants Considered for 2007-2017

Year	Generation Unit added	Power MW	Observations
2007	1 GT 150 MW Natural Gas - CC	150	
2008	1 GT 150 MW + 1 HT 150 MW Natural Gas – CC	300	Both are complemented: 450 MW CC
2010	1 GT 150 MW Natural Gas - CC	150	
2011	1 GT 150 MW + 1 HT 150 MW Natural Gas – CC	300	Both are complemented: 450 MW CC
2013	2 GT 150 MW + 1 HT 150 MW Natural Gas – CC	450	
2016	1 GT 150 MW Natural Gas - CC	150	
2017	1 GT 150 MW + 1 HT 150 MW Natural Gas – CC	300	Both are complemented: 450 MW CC

Total: 1,800 MW in new units with Natural Gas technology- all of them CC.

Source: Peru's Sectoral Baseline Study (2003).

$O\&M_i$: Annual O&M costs (including fuel) to attend the additional demand for year I, includes O&M of both existent and new plants that get to satisfy the incremental demand, according to a dispatch simulation made for each year (of the period 2007-2017). The Costs of O&M, basically fuel

costs, were not calculated in a direct manner with a load factor, but instead, they were the result of a Dispatch Simulation. The dispatch simulation considered monthly load factor variations and monthly hydro supply variations. The dispatch simulation also considered temporal shutting down of plants' operations for maintenance purposes. Thus, in each month of the period in question, the production of fossil fuel fired plants is a function of the hydroelectric supply (function of the hydrological projected conditions) and the demand.

O&M Composition:
a) Variable Costs of Fuel (US$/MWh)
Fuel price (c$/$10^6$ Kcal) and specific caloric consumption (Kcal/KWh).
The latter was obtained from the specific fuel consumption (g/kWh) and the caloric value of the fuel in question (Kcal/Kg) – the specific caloric consumption at minimum charge and the incremental consumption were obtained from statistics of engines' power and performance trials recorded by *COES*

The Fuel prices[68] taken were the 2002's, because after that year the prices are biased by the War with Irak:

Liquid-Fuel Prices used for the LRMC Calculation

Plant	Fuel Type	Soles[69]/Gln	$/Gln	$/Barrel	$/Ton	Kg/Gln (density)
Callao	D2	2.94	0.84	35.28	258.62	3.248
	R6	2.43	0.69	29.16	192.22	3.612
	R500	2.38	0.68	28.56	185.03	3.675
Mollendo	D2	2.93	0.84	35.16	257.74	3.248
	R500	2.42	0.69	29.04	188.14	3.675
Ilo	D2	2.96	0.85	35.52	260.38	3.248
	R6	2.46	0.70	29.52	194.59	3.612

Source: Peru's Sectoral Baseline Study (2003).

Non-Liquid Fuel Prices used for the LRMC Calculation

Coal Price	ILO2 is the only coal-fired thermal plant in Peru. It uses imported coal, which price is a function of standard coal with superior calorific power of 6,240 Kcal/Kg. The coal price assigned to this plant by *COES* and *OSINERG* is $38.9/MT
Natural Gas Price	Malacas TG-4 and Aguaytia Gas Prices considered were those of the 2003 projection made by *OSINERG*, which was $2.199/MMBTU - the price of the Camisea Gas is much lower ($1/MMBTU for the electric sector)

Source: Peru's Sectoral Baseline Study (2003).

b) Non-Fuel Variable Costs
These costs were taken from *OSINERG* reports. These cost comprise Variable Costs of additives, lubricants, spares, materials and other maintenance expenses - all expressed in US$/MWh.

c) O&M Fixed Costs

[68] Do not include Selective Consumption Tax (ISC), because ISC is exonerated for electricity generators. V.A.T is not included because this is recovered by the generating company as a fiscal credit when it sells its energy produced.
[69] Exchange rate: 3.5 Soles/$.

These costs were taken from *MINEM* reports. These costs comprise fixed costs of payroll expenses for employees in charge of the plant operation, plant supervision, plant maintenance, plant security and other general expenses-all expressed in US$/KW- month.

O&M for new plants

Units	Code	Max. Power	Min Power	Specific Caloric Consumption		Fuel Cost	O&M Costs	
		Max	Min	Incremental	Min	Domestic	Fixed Cost	V. Cost
		KW		Kcal/kWh		c$/10^6Kcal	$/KW-month	$/MWh
GT 100 MW	G100	100	25	2300	3340	856.3	1	4
GT 150 MW	G150	150	38	1960	3424	856.3	0.7	3
CC 2 GT 100 + 1 HT 100	C300	300	150	1400	2013	856.3	1.4	2.4
CC 2 GT 150 + 1 HT 150	C450	450	225	1250	1851	856.3	0.98	1.8

Source: Peru's Sectoral Baseline Study (2003).

NSE_i: Non-served energy in year I (assumed to be zero, because this effect was incorporated in the *Di* variable)

D_i: Additional Demand in year i
Projections for 2007-2017 were based on *OSINERG* projections from 2003-2007 and the following assumptions:

a) Both GDP and population growth will maintain their average growth of the 2003-2007 period.

b) Price of electricity generation will maintain the 2003-2007 *OSINERG* Projection

c) Energy losses in distribution and transmission will be kept at levels projected for 2007 by *OSINERG*.

d) Demand will be equal to *OSINERG* projection for the 2007, and from 2008 to 2017, the demand from mining projects will increase at 5% annually.

e) The future interconnection with Ecuador will cause exports from Peru to Ecuador only. The demand of Ecuador is added to the demand of Peru in wet months, from December to April up (147 GWh) for all the period 2007-2017

The results for the projected demand are:

***SEIN* Demand Projection**

Year	Power MW	Energy GWh	Power Growth Rate	Energy	Load Factor
2007	3480	24062	3.22%	3.63%	78.9%
2008	3603	24935	3.55%	3.63%	79.0%
2009	3731	25789	3.55%	3.42%	78.9%
2010	3864	26681	3.55%	3.46%	78.8%
2011	3999	27588	3.51%	3.40%	78.7%
2012	4143	28549	3.58%	3.48%	78.7%
2013	4291	29539	3.59%	3.47%	78.6%
2014	4445	30563	3.57%	3.47%	78.5%
2015	4602	31618	3.55%	3.45%	78.4%
2016	4766	32710	3.55%	3.45%	78.4%
2017	4935	33839	3.55%	3.45%	78.3%

Source: Peru's Sectoral Baseline Study (2003)

N: Number of years in the period of analysis *(i = 1, ...,n)*
Period = 2007-2017

<u>Annex 4</u>

MONITORING PLAN

Monitoring Plan

For

Poechos I

First Crediting Period (2004-2011)

November 2004

GLOSSARY

APFR: Annual Plant Fuel Requirement (TJ)
Baseline Emissions: Product of EFy times EGy
BLS: Latest Baseline Study
BM: Build Margin Emission Factor
CDM: Clean Development Mechanism
CERs: Certified Emission Reductions
CM: Combined Margin Emission Factor
COEF: tCO_2e/MWh
***COES*:** Committee of Economical Operation of the *SEIN* (Dispatch Center)
DDA-OM: Dispatch Data Analysis Operating Margin Emission Factor
EFy: Baseline Emission Factor (tCO_2e/MWh)
EGy: The Project's annual generation (MWh)
ENOSA: Electronoroeste S.A (The Project Final Client)
ERPA: Emissions Reductions Purchase Agreement
ERCP: Emissions Reductions Calculation Procedure
ERs: Green House Gases Emissions Reductions
GHG: Green House Gases
HP: Hydropower plant (s)
Merit Order: Grid Dispatch Weekly Merit Order
Monthly Merit Order: Average of Four Weekly Grid Dispatch Merit Orders
MP: Monitoring Plan
NCDMF: Netherlands Clean Development Mechanism Facility
NEC: Net Efficiency Conversion
OM: Operating Margin Emission Factor
Project Staff: Team or person assigned and trained to perform the ERCP
***SEIN*:** National Electric Grid
The Operator: SINERSA (The Project Operator)
TP: Thermal plant (s) fossil fuel-fired plants

TABLE OF CONTENTS

I. Background Information
The baseline methodology and monitoring methodology for Poechos I, are in accordance with the approved consolidated baseline methodology (ACM0002): Consolidated baseline methodology for zero-emissions grid-connected electricity generation from renewable sources ("The Methodology"). The Methodology was released in September 3rd, 2004 by the Clean Development Mechanism-Executive Board.

Poechos I ("The Project") installed capacity and projected yearly average generation is as follows:

Project name	Installed capacity (MW)	Generation (GWh/yr)
Poechos I	15.2	57.740

Source: The Sponsor

The Project is a hydroelectric power plant located in Peru, in the Northwestern Department of Piura. The Project will displace 31,463 tCO_2e (approx.) per year, which account for 220,241 tCO_2e (approx.) for the first crediting period (7 years). Methane and Carbon Dioxide are negligible. Therefore there is not need to monitor leakage and it will not be taken into account when calculating ERs.

The spatial extent of The Project boundary is the *SEIN*. The Project is connected to the *SEIN* through the Sullana Substation, which belongs to Electronoroeste S.A. (ENOSA). The 57.740 GWh (approx.) of electricity generated per year will be sold to ENOSA, a stated-owned enterprise. Until now, neither electricity exports from the *SEIN* nor electricity imports to the *SEIN* have taken place.

II. Purpose of the Monitoring Plan
This report presents the Monitoring Plan (MP) for The Project, which has been considered by The Netherlands Clean Development Mechanism Facility (NCDMF) for ERs purchases in Peru. The MP defines a standard against which the performance in terms of The Project's ERs will be monitored and verified, in conformance with all relevant requirements of the Clean Development Mechanism (CDM) of The Kyoto Protocol. The MP is part of the ERPA Document and, after its validation, will be an integral part of the contractual agreement between The NCDMF, The Project Developer and The Project Operator (the Operator). As of today, The Project's Developer is the same enterprise as The Project's Operator: SINERSA. The CDM defines monitoring as the systematic surveillance of a project's performance by measuring and recording performance-related indicators relevant to the project activity. Both the Baseline Study (BLS) and the MP are subject to verification procedures.

III. Use of the Monitoring Plan by the Operator
This report, the MP, identifies key performance indicators of The Project and sets out the procedures for metering, monitoring, calculating and verifying the ERs generated by The Project, annually. Adherence to the instructions in the MP is necessary for the Operator to successfully measure and track the impact of The Project and prepare all data required for the periodic audit and verification process that must be undertaken to confirm the achievement of the corresponding ERs. The MP is thus the basis for the production of ERs and delivery of ERs to The NCDMF.

The MP assists the Operator in establishing a credible, transparent, and adequate data measurement, collection, recording and management system to successfully develop and maintain the proper information; required for an audit and for the verification and certification of the achieved ERs and other Project outcomes. Specifically, the MP provides the requirements and instructions for: (i) establishing and maintaining the appropriate monitoring system including spreadsheets for the calculation of ERs, (ii) checking whether The Project meets key sustainable development indicators, (iii) implementing the

necessary measurement and management operations, and (iv) preparing for the requirements of independent third party verifications and audits.

The MP ensures environmental integrity and accuracy of crediting ERs by only allowing actual ERs to be accounted for after they have been achieved. The MP must therefore be used throughout the period in which The Project has committed to or desires to sell/track ERs. It must be adopted as a key input into the detailed planning of The Project, and included as one of the operational manuals of The Project.

The MP can be updated and adjusted to meet operational requirements - the Verifier approves such modifications during the process of initial or periodic verification. In particular, any shifts in the baseline scenario may lead to such amendments, which may be mandated by the Verifier. Amendments may also be necessary as a consequence of new circumstances that affect the ability to monitor ERs as described here or to accommodate new or modified CDM rules.

I.V. Organizational, Operational and Monitoring Obligations
A. Obligations of the Operator
Monitoring performance of The Project requires the fulfillment of operational data collection and processing obligations from the Operator. The Operator has the primary obligation of ensuring that sufficient and accurate information is available to calculate ERs in a transparent manner and of allowing for a successful verification of accounted ERs.

The Operator must gather and process information needed to monitor ERs. It is required that the Operator calculate its ERs based on most recent available information, following The ERs Calculation Procedure (ERCP), presented in this report.

All data required for the MP will come from *COES* and; from The Project's final client, ENOSA[70]. Data gathering and processing should be done monthly by the Operator, as follow:

	At the end of each month:
COES **(Data Provider)**	-Report of hourly generation of the *SEIN*'s units (measurement: 15' or 30' [71]) -Report of weekly dispatch merit orders for "hours of maximum demand [72]" -Real NECs per power plant in the *SEIN*.
ENOSA (Data Provider)	-Report of The Project hourly generation purchased by ENOSA.
Operator (Data processor)	-Verification of ENOSA's report of The Project hourly generation – comparison with own records; back up of any claims with receipt of sales -Monthly data filling in all the spreadsheets required, following the ERCP -Monthly report to The NCDMF

Source: Own production.

The Operator should calculate ERs on the basis of this MP (following the ERCP) for the purpose of claiming ERs credits. It is believed that the MP approach presented here will result in an accurate, yet conservative calculation of ERs. However some uncertainties may lead to a deviation of monitored ERs and the verified ERs, especially errors in the data monitoring and processed system. The Operator is

[70] As long as The Project Operator is not an active member of *COES*; when it is, all data will come from *COES*
[71] Half an hour measurement is still acceptable if total *SEIN* production calculated with it, does not deviate greatly (i.e. less than 1%) from total *SEIN* Production calculated with the 15-minute measured data
[72] (6pm to 11 pm) to set a standard - weekly merit orders for hours of maximum, minimum and medium demand are similar

expected to prevent such errors and the verification audits are expected to uncover any possible errors. The CERs would be granted ex-post verification.

B. Estimated Anthropogenic Emissions for The Project:
The Methodology stipulates that the Baseline of The Project is the Combined Margin Emission Factor, which is the average of the Operating Margin Emission Factor and the Build Margin Emission Factor. Estimated anthropogenic emissions were calculated for The Project following a 4-step-process:

Step 1 – Calculation of the Operating Margin Emission Factor (OM)
Step 2 – Calculation of the Build Margin Emission Factor (BM)
Step 3 – Calculation of the Baseline Emission Factor (CM)
Step 4 – Calculation of The Project's Emissions Reductions Prior to Validation

Step 1 – Calculation of the Operating Margin Emission Factor
Out of four options for the OM, the Dispatch Data Analysis Operating Margin Emission Factor (DDA-OM) was taken; as it constitutes the first methodological choice where data is available, according to The Methodology.

The formula for the DDA-OM used was provided by The Methodology:
EF_OMy Dispatch Data (tCO_2e/MWh)= E_OMy/EGy
E_OMy = Sum of [average tCO_2e/MWh emitted by plants that fall within top 10% of grid system dispatch each hour of the year "times" The Project generation in MWh each hour of the year]
EGy = The Project Generation in the year

For this calculation the BLS used the units' hourly generation of 2003, which was the most recent statistic data available. Because at the time the BLS was completed, The Project hourly generation data for a whole year was inexistent, it was assumed that The Project operated at full capacity and dispatched equally during all hours of the year.

Considering this assumption, the variables were defined as follow:
-EGy: An "approximation" to MWh generated in 2003 by The Project -It was obtained from multiplying Installed Capacity (MWh) of The Project times 8760.
-EGh: An "approximation" to MWh generated in each hour of 2003 -It assumed that The Project produced at its full installed capacity (15.2MWh) each hour.
-Fi,n,h: Electricity output in MWh hourly produced in 2003 by each unit of the *SEIN* that fall within the top 10% of grid dispatch.
-COEFi,n[73]: The tCO_2e/MWh factors assigned to each unit of the *SEIN* according to its technology – For hydropower plants the COEF = 0.

The information of hourly generation of all *SEIN* units and their COEF associated was organized in columns, where the position of the columns was sorted according to a "monthly grid dispatch merit order" calculated[74]. This organization helped to identify the plants that fall within top 10% of grid dispatch each hour of the year.

The BLS's resulting Dispatch Data Analysis Operating Margin Emission Factor was 0.72614 tCO_2e/MWh and was obtained from dividing E_OMy by EGy =96,688/133,152.

[73] COEFs assigned to each unit of the *SEIN* will vary according to the NECs published by COES yearly.
[74] This was done by a simple average of the four weekly Santa Rosa Equivalent Cost Soles/MWh (merit orders) assigned to each unit of the *SEIN*, by *COES*, in a month.

E_OMy:	SUM Egh*EF_DDh	96,688	133,152	:EGy
EOMy/Egy:	**Operating Margin**	**DDA_OM**	**0.72614**	**:EF_OMy DD (TCO2/MWh)**

Source: Own production with *COES* information.

Step 2 – Calculation of the Build Margin Emission Factor

According to the Methodology, the BM is defined as the generation-weighted average emission factor of either the 5 most recent or the most recent 20% of power plants built (in generation), whichever group's annual generation is greater. Both samples should exclude CDM-Status Plants[75]. Out of the 2 options for the BM, option 2 was selected; this option does not include in-construction plants in the samples and requires an annual ex-post calculation for the first crediting period. The formula to apply to the selected sample is provided by The Methodology:

EF_BMy (tCO_2e/MWh) = [∑I,m Fi,m,y,*COEFi,m] / [∑mGENm,y]

F=Generation of each plant of the selected sample

COEF=tCO_2e/MWh of each plant of the selected sample;

GEN=Generation of each plant of the selected sample

In the BLS, any increase in installed capacity in the *SEIN* was identified and considered only if the increase was made in new units added (No: upgrades, rehabilitations or interconnections of old units). The following list shows the capacity additions (new units') in the *SEIN* from 1988 to 2003, and their annual generation. As The Project did not generate yet, the annual generation of the additions taken was the average of their three most recent year's generations.

[75] As of today, The Project is the only CDM-Status Plant of the *SEIN*

Additions to the *SEIN* (1988-2003)[76]

Years	Techn	Addition Category	Install.Cap. Added (MW)	2001 Gen (GWh)	2002 Gen (GWh)	2003 Gen (GWh)	Annual Generation (GWh)
1988							
C.H. CARHUAQUERO	HYDRO	Newly built	75.1	469.27	479.41	458.78	**469.16**
CHARCANI (I-V)	HYDRO	Newly built	136.80	842.17	641.80	660.24	**714.74**
1993							
TG VENTANILLA 2	D2	Newly built	100	2.40	2.45	1.54	**2.13**
TG VENTANILLA 1	D2	Newly built	100	2.40	2.45	1.54	**2.13**
1995							
CALANA	R6	Newly built	19.2	33.02	25.72	45.81	**34.85**
1996							
STA. ROSA WESTING	D2	Newly built	127.7	9.41	5.61	11.60	**8.88**
1997							
C.H. GALLITO CIEGO	HYDRO	Newly built	34.0	183.53	149.71	121.79	**151.68**
TG VENTANILLA	D2	Newly built	184.0	4.41	4.51	2.83	**3.92**
MOLLENDO MIRLESS	R500	Newly built	31.7	10.98	9.53	35.37	**18.63**
1998							
AGUAYTIA 1	GAS	Newly built	86.3	230.80	412.26	466.80	**369.95**
AGUAYTIA 2	GAS	Newly built	86.3	216.30	332.89	367.97	**305.72**
TG MALACAS	PM GAS	Newly built	102.2	206.23	181.35	274.30	**220.63**
1999							
SAN GABAN II	HYDRO	Newly built	55.0	357.38	376.19	356.34	**363.30**
CALANA	R6	Newly built	6.4	11.01	8.57	15.27	**11.62**
MOLLENDO TGM	D2	Newly built	90.0	0.73	0.86	1.43	**1.01**
2000							
SAN GABAN II	HYDRO	Newly built	58.1	377.51	397.38	376.41	**383.76**
ILO2 TVC	COAL	Newly built	145.0	338.78	845.93	859.44	**681.38**
C.H. CHIMAY	HYDRO	Newly built	156.0	724.76	752.96	825.87	**767.86**
C.H. YANANGO	HYDRO	Newly built	42.3	214.60	239.13	202.28	**218.67**
2001							
TUMBES	R6	Newly built	18.3	22.38	20.73	27.99	**24.36**
2002							
C.H. HUANCHOR	HYDRO	Newly built	18.9	-	36.86	144.64	**144.64**
2003							
YARINACOCHA	R6	Newly Built	25.6	-	-	56.88	**144.97**

Source: Own production with *COES* information

Out of this list, the 5 most recently built plants up to 2003 were: 1)Yarinacocha, 2) Huanchor, 3)Tumbes, 4)Yanango and 5) Chimay, and their comprised annual generation was 1,300.5 GWh. Since the annual generation of the 20% most recently built was greater, 3,860.08 GWh, the latter group was selected for the BM calculation. The 20% most recently built plants in generation comprises the whole list above except for 1988 capacity additions in the *SEIN*[77].

The selected sample of Newly Built plants was organized (clustered) by type of fuel and each type of fuel annual electricity generation was transformed back to its fuel consumption caloric value through the Annual Plant Fuel Requirement formula[78] and multiplied by C x O[79] x 44/12 (mass conversion factor).

[76] San Gaban appears twice because increases on its installed capacity were 2 units, the first one was put in operation in 1999 and the second one in 2000 – each unit generation was considered accordingly

[77] Exactly, the selected sample's generation comprised 19.69% (or 20% rounded to the nearest integer) of 2001-2003 average annual generation of the *SEIN*

[78] Fully explained in the ERCP

The total tCO_2e per fuel type that way obtained was summed up and the result was divided by the total generation (MWh) of the selected sample. Hence a weighted average tCO_2e/MWh of the selected sample was obtained.

The BLS' resulting BM2 was 0.36371 tCO_2e/MWh, and was obtained from dividing total tCO_2e emitted by the selected sample "by" total gen. of the selected sample.

Technologies in Selected Sample	Most Recent Year Gen (GWh)	% per technology	APFR	C	O	44/12	CO2 Emissions(tCO2)
Coal	681.38	18%	7,433.28	25.80	0.980	3.67	689,124
d2	18.06	0%	186.12	20.20	0.990	3.67	13,647
r6	215.80	6%	1,807.54	21.10	0.990	3.67	138,445
r500	18.63	0%	204.82	21.10	0.990	3.67	15,688
Dry Gas	675.68	18%	7,484.40	15.30	0.995	3.67	417,776
Pure Methane Gas	220.63	6%	2,443.85	14.50	0.995	3.67	129,282
Dry Gas CC	0.00	0%	0.00	15.30	0.995	3.67	0
Hydro	2,029.91	53%	0.00	0.00	0.000	0.00	0
TOTAL	3,860.08	100%					1,403,961

BM2=	0.36371	tCO2//MWh

Source: Own production with *COES* information.

Step 3 – Calculation of the Baseline Emission Factor

The Baseline Emission Factor was calculated as a combined margin (CM), consisting of the simple average[80] of both the resulting OM and the resulting BM. All margins are expressed in tCO_2e/MWh.

CM = 0.5*OM + 0.5*BM

CM = 0.5*(0.72614) + 0.5*(0.36371) = 0.54493 tCO_2e/MWh

The BLS's resulting Baseline Emission Factor was 0.54493 tCO_2e/MWh.

Step 4 – Calculation of The Project's Emissions Reductions Prior to Validation

Because The Project itself does not produce any emission, no leakages entered into the calculation of estimated ERs, and the baseline emissions were estimated to be equal to The Project ERs.

The estimated ERs per year for The Project were obtained from the following multiplication:

Estimated Baseline Emissions = CM* (Estimated Annual Project Generation in MWh)

Estimated ERs per year = CM* (Estimated Annual Project Generation in MWh)

Estimated ERs per year = 0.54493 tCO_2e/MWh * 57,740 MWh = 31,463 tCO_2e or 31,463 ERs

Assuming the 3 most recent years (data used for the BSL calculations) were average years in hydrological conditions. The ERs per year estimated for the first crediting period are:

Estimated ERs for the first crediting period = 31,463 tCO_2e/yr*7 yrs = 220,241 tCO2e or Estimated ERs[81].

C. Emissions Reductions Calculation Procedure and Required Spreadsheets

The Emissions Reductions Calculation Procedure (ERCP) is the basic instrument for gathering, recording and processing information that will result in the measured ERs. The Operator shall keep The Project ERCP as a manual. The ERCP should contain: i) data gathered from The Project final client: ENOSA[82], ii) data gathered from *COES* information system, and iii) data processed by the Operator. All data processing should be done in Excel. The ERCP is designed for monthly calculation, based on final

[79] C and O use IPCC-1996 world wide values per fuel type

[80] The default weights (50%,50%) were kept

[81] All margins were rounded to the fifth decimal, but the CERs per year was rounded down to the nearest integer. The exact generation herewith considered is 57,739.5 MWh/yr, this generation does not need to be rounded down to the nearest integer.

[82] When the Project Operator becomes an active member of *COES*, all data will come from *COES*

monthly *COES* reports and the final client monthly recording. Although it will only be possible to know the ERs at the end of each year (March 31st for The Project), filling data monthly in the required spreadsheets will provide time to review formulas, minimize errors and have data readily available for the Verifier in any period of the year. **There are only 2 required spreadsheets to update with new data: Poechos DDA-OM.xls and Poechos BM2.xls.** The names of these files should be kept but should also reflect the date for which the latest adjustment is made.

DDA-OM Spreadsheet:
This excel file contains all data and formulas necessary to calculate the Dispatch Data Analysis Operating Margin. The data's year is the year of project generation (April1st-March31st). 14 worksheets compose the DDA-OM Spreadsheet:
-Worksheet #1: COEFs (tCO_2e/MWh) to assign to each unit of the *SEIN* along the first crediting period[83].
-Worksheet #2: Calculation of monthly grid dispatch merit order for all thermal units of the *SEIN*.
-Worksheet #3 to Worksheet #14: One worksheet per month of the year; they contain the *SEIN* units hourly generation.

Worksheet #1

Table # 1: COEF by Technology[84]

Current Technologies in the *SEIN*

Type of Fuel	COEF(tCO2/MWh)
Coal	1.01
Oil based	0.80
Diesel 2	0.76
Residual 6	0.64
R500	0.84
Gas	0.61
Dry	0.62
Pure Methane	0.59
Hydro	0.00
Residual 6 and Diesel 2	0.66
Pure Methane or Diesel 2	DEPENDS
ILO TV2 Cogeneration Plant	0.34

Future Technologies in the *SEIN*

Type of Fuel	COEF (tCO2/MWh)
MIX	weigthed average of fuel COEFs
Change fuel type	each month (first week of the month)
Diesel CC	0.48
Residual CC	0.50
Gas Dry CC	0.37
Gas PM CC	0.35
Coal CC	0.61
Diesel Cogeneration	0.33
Residual Cogeneration	0.34
Gas Dry Cogeneration	0.25
Gas PM Cogeneration	0.24
Coal Cogeneration	0.42

Source: Own production.

Table#1'COEFs will be updated yearly according to real NECs published in COES Statistics. The formula to use to calculate the COEFs per technology for Table 1 is:
COEFs per technology = [3.6 x (44/12) x C x O] / [10^3 x NEC average per technology]. Future technologies in the SEIN should be updated as well with real NECs data of the future.

The following table relates each unit of the *SEIN* to a COEF, according to the technology the unit uses. The assignation of COEFs, shown in Table #2, is to be taken from Table 1.

Table#2: Name Plant / Technology/Assigned COEF

Table #2, holds up to 100 units (no more than 34 HPs and 66 TPs), 81 that operated in 2003 (27 HPs and 54 TPs) and 19 future units (7 HPs and 12 TPs) that are set aside a space. Future units' data should be filled as the arrows in Table#2 indicate, as they enter the *SEIN*. Units that did not dispatch in any hour of the year in question should not be considered for the DDA-OM Calculation at all, so that they do not occupy extra-space, unnecessarily.
Table#2 below shows the technical name of the *SEIN* unit (the way *COES* has it registered), complete name of the plant, technology and assigned COEF.

[83] COEF will vary according to yearly published NECs per plant. Annual real NECs average per technology will have to be considered for the COEFs per technology calculation.
[84] CC: Combined cycle technology

Table #2 COEFs that show “DEPENDS” indicate that the plant changes the fuel it burns in several weeks of the year. For this plant the fuel that is burned in the first week of the month should be taken as an assumption for the plant’s fuel burned for the month, and the COEF related to that type of fuel should be taken for the month.

ag_tg1	AGUAYTIA 1 (2)	Dry	0.62
ag_tg2	AGUAYTIA 2 (2)	Dry	0.62
arcata	Arcata	Hydro	0.00
aricota	CH ARICOTA	Hydro	0.00
bvista1	BELL MAN 1,2	Diesel 2	0.76
bvista2	BELL MAN 1,2	Diesel 2	0.76
cahua	Cahua	Hydro	0.00
calana123	CALANA 123	Residual 6	0.64
calana4	CALANA 4	Residual 6	0.64
call	CH Callahuanca	Hydro	0.00
ccomb	C. COMBINADO	Diesel 2	0.48
chariii	CH CHARCANI	Hydro	0.00
chariv	CH CHARCANI	Hydro	0.00
charv	CH CHARCANI	Hydro	0.00
charvi	CH CHARCANI	Hydro	0.00
chi_slz12	SULZER CHILINA	Diesel 2	0.76
chicl_o	DS CHICLAYO OESTE-D	Diesel 2	0.76
chiltv1	chiltv1	R500	0.84
chiltv2	TV2 CHILINA	R500	0.84
chiltv3	TV3 CHILINA	R500	0.84
chimay	CH Chimay	Hydro	0.00
chimb	TG1 CHIMBOTE	Diesel 2	0.76
cnp_mann	DS PACAS-MAN	Residual 6 and Diesel 2	0.66
cnp_slz	DS PACAS-SULZER	Residual 6	0.64
cpato	CH Cañón del Pato	Hydro	0.00
cqro	CH Carhuaquero	Hydro	0
dolores1	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.76
dolores2	DOL ALCO 1-2 GM 1-2-3	Diesel 2	0.76
gciego	CH Gallito Ciego	Hydro	0
herc	CH HERCA	Hydro	0
hp1	HP1	Hydro	0
hp2	HP2	Hydro	0
hp3	HP3	Hydro	0
hp4	HP4	Hydro	0
hp5	HP5	Hydro	0
hp6	HP6	Hydro	0
hp7	HP7	Hydro	0
hpni	CH Huampaní	Hydro	0
huanchor	CH Huanchor	Hydro	0
huin	CH Huinco	Hydro	0
ilo1catk	KATCATO (ENERSUR)	Diesel 2	0.76
ilo1tg1	TG1 ILO	Diesel 2	0.76
ilo1tg2	TG2 ILO	Diesel 2	0.76
ilo1tv1	ILO TV1	R500	0.84
ilo1tv2	ILO TV2	R500	0.34
ilo1tv3	ILO TV3	R500	0.84
ilo1tv4	ILO TV4	R500	0.84
ilo2_carb	TV CARBON ILO II	Coal	1.01
machup	CH MACHUPICCHU	Hydro	0
mal_tg1	TG1	Pure Methane or Diesel 2	DEPENDS
mal_tg2	TG2	Pure Methane or Diesel 2	DEPENDS
mal_tg3	TG3	Pure Methane or Diesel 2	DEPENDS
mal_tg4	TGN4	Pure Methane	0.59
malp	CH Malpaso	Hydro	0
man	CH MANTARO	Hydro	0
mat	CH Matucana	Hydro	0
moll123	MOLLENDO 1,2,3	R500	0.84
molltg1	TGM1 MOLLENDO	Diesel 2	0.76
molltg2	TGM2 MOLLENDO	Diesel 2	0.76
moq12	MOQUEGUA	Diesel 2	0.76
moy	CH Moyopampa	Hydro	0
oro_p	CH Oroya-Pachac.	Hydro	0
paita1	DS PAITA1	Diesel 2	0.76
paita2	DS PAITA2	Diesel 2	0.76
pariac	Pariac	Hydro	0
piura1	DS PIURA1	Diesel 2	0.76
piura2	DS PIURA2	Diesel 2	0.76
ron	CH RESTITUCION	Hydro	0
sgab2	CH SAN GABAN	Hydro	0
shcummins	CUMMINS	Diesel 2	0.76
shou_tv1	TV1 SHOUGESA	R500	0.84
shou_tv2	TV2 SHOUGESA	R500	0.84
shou_tv3	TV3 SHOUGESA	R500	0.84
sullana	DS SULLANA	Diesel 2	0.76
taparachi	TAPARACHI	Diesel 2	0.76
tg_piu	TG PIURA	Diesel 2	0.76
tintaya	TINTAYA	Diesel 2	0.76
tp55	TP55	Unknown	0
tp56	TP56	Unknown	0
tp57	TP57	Unknown	0
tp58	TP58	Unknown	0
tp59	TP59	Unknown	0
tp60	TP60	Unknown	0
tp61	TP61	Unknown	0
tp62	TP62	Unknown	0
tp63	TP63	Unknown	0
tp64	TP64	Unknown	0
tp65	TP65	Unknown	0
tp66	TP66	Unknown	0
truji	TG TRUJILLO	Diesel 2	0.76
trupal	TRUPAL	Residual 6	0.64
tumbes	TUMBES	Residual 6	0.64
uti_5	TG S.ROSA UTI5	Diesel 2	0.76
uti_6	TG S.ROSA UTI6	Diesel 2	0.76
vent3	TG VENTANILLA-3	Diesel 2	0.76
vent4	TG VENTANILLA-4	Diesel 2	0.76
westin	TG WESTINGHOUSE	Diesel 2	0.76
yanan	CH Yanango	Hydro	0
yarinac	Yarinacocha (5)	Residual 6	0.64
yaupi	CH Yaupi	Hydro	0

← Start filling from HP7 to HP1. COEFs remain 0 for the seven HPs.

← Start filling from TP55 to TP66. COEFs remain 0 for yet to exist TPs.

Source: Own production with COES data of plants and type of fuel.

Worksheet #2: Monthly Merit order Calculation

The 52 weekly merit orders[85] for **"hours of maximum demand"** should be averaged in this Worksheet #2:

April - 1st Week most recent year

Unit Name	Sta Rosa Eq-C (S/KWh)
Sorted by name	x

April-most recent year

Unit Name	Sta Rosa EC (S/KWh)
Sorted by name	Monthly Average Merit Order

April-most recent year

Unit Name	Sta Rosa EC (S/KWh)
Name	Sorted by Monthly Average Merit Order

April - 2nd Week most recent year

Unit Name	Sta Rosa Eq-C (S/KWh)
Sorted by name	x

Visible Average Function

April - 3rd Week most recent year

Unit Name	Sta Rosa Eq-C (S/KWh)
Sorted by name	x

April - 4rd Week most recent year

Unit Name	Sta Rosa Eq-C (S/KWh)
Sorted by name	x

….. 12 monthly merit orders need to be obtained from April through March.

Worksheet #3 to Worksheet #14: Hourly Generation of the *SEIN* Units

12 monthly worksheets that contain the *SEIN* units' hourly production in each month of the most recent year (April-March) should be identical in # of columns, formulas, "general organization" but not in data. Worksheets #3' – Worksheet #14' columns C to CY should be organized as follow:

COEFs:	0	0	0	0	0	0.34	0.76	0	0
TECHNOLOGY:	hydro	hydro	hydro	hydro	hydro	r-500	diesel	unknown	unknown
Hours of the month	HP 1…	...HP7	CH Mantaro	…	Canhon del Pato	ILO T2 Cog	Dolores	TP55	T66
1									
.	Future HPs		Existing HPs			Existing TPs		Future TPs	
.	◄--------				---------	---------			--------►
.	There is an unchangeable pre-defined order for existing					Existing TPs should be placed according to			
744	and future HPs - for all the crediting period					grid dispatch merit order, future TPs are placed last			

Source: Own production

Hydropower plants' (existent and future) hourly generation should occupy the **D to AK columns only. Thermal plants'** (existent and future), the **AL to CY** columns only. The predefined order for HPs is shown below (Where the "-1 position" =D column and "27th position" =AK column). This order should hold for the first crediting period. TPs should be sorted according to their grid dispatch monthly merit order calculated. As future HPs (max.7) are kept a space (columns) in the left extreme of columns D to AK; future TPs (max. 12) should be kept a space (columns) in the right extreme of columns AL to CY (like they were occupying the least monthly merit order of grid system dispatch). Finally, the *SEIN* units' associated COEFs should be placed in the first row of the corresponding unit's column. For yet-to-exist plants COEF=0.

[85] The merit order is given by the Santa Rosa Equivalent Cost (Soles/MWh) assigned to a unit, according to its efficiency.

Predefined order from left to right (D to AK) for all HPs[86]

-7	hp1	HP1
-6	hp2	HP2
-5	hp3	HP3
-4	hp4	HP4
-3	hp5	HP5
-2	hp6	HP6
-1	hp7	HP7
1	Hydro	CH MANTARO
2	Hydro	CH RESTITUCION
3	Hydro	CH Huinco
4	Hydro	CH Matucana
5	Hydro	CH Yaupi
6	Hydro	CH Oroya-Pachac.
7	Hydro	CH Malpaso
8	Hydro	Cahua
9	Hydro	Pariac
10	Hydro	Arcata
11	Hydro	CH Gallito Ciego
12	Hydro	CH Callahuanca
13	Hydro	CH Moyopampa
14	Hydro	CH Huampaní
15	Hydro	CH Chimay
16	Hydro	CH Yanango
17	Hydro	CH Huanchor
18	Hydro	CH Carhuaquero
19	Hydro	CH ARICOTA
20	Hydro	CH CHARCANI
21	Hydro	CH CHARCANI
22	Hydro	CH CHARCANI
23	Hydro	CH MACHUPICCHU
24	Hydro	CH HERCA
25	Hydro	CH SAN GABAN
26	Hydro	CH CHARCANI
27	Hydro	CH Cañón del Pato

Source: Own production

The formula component of each monthly worksheet (W#3–W#14) is given by columns CZ to FD (not shown in this report). Formulas will use data entered in columns D to CY and will bring a resulting DDA-OM. The **only data column in this set is EE which should be filled with The Project hourly generation**. The resulting DDA-OM will show up at the low end of column EE in W# January.

The BM2 Spreadsheet:
This excel file, composed by four worksheets, contains all the calculations necessary to update the BM2. The data's year is the year of The Project generation.
-Worksheet #15: *SEIN* Installed Capacity (March 31st 2004 to March 31st 2011)
-Worksheet #16: New units built' annual generation in the year of The Project generation.
-Worksheet #17: The BM2 Calculation in the year of The Project generation.
-Worksheet #18: The Baseline Emission Factor and ERs in the year of The Project generation.

[86] The only difference between negative and positive positions is that negatives' are for inexistent plants until the moment (up to March 2004). Even when they start to exist they should keep that position. Note that Future HPs are kept a space (column) on the left extreme of Worksheet #3-Worksheet #14.

Worksheet #15: 2004-2011 *SEIN* Installed Capacity

SEIN Installed Capacity March 2004 | 3/2005 SEIN Installed Capacity ... 3/2011 SEIN Installed Capacity

PLANT	INSTALLED CAPACITY (MW)
TERMOSELVA	
AGUAYTIA 1	86.294
AGUAYTIA 2	86.294
CAHUA S.A.	
CAHUA	43.600
PARIAC	5.216
E. PACASMAYO	
PACASMAYO	24.617
GALLITO CIEGO	38.147
ARCATA	**5.098**
EDEGEL	
HUINCO	258.400
MATUCANA	128.578
CALLAHUANCA	75.059
MOYOPAMPA	89.250
HUAMPANI	31.360
YANANGO	42.300
CHIMAY	156.000
HUANCHOR	18.860
SANTA ROSA WTG	127.700
SANTA ROSA UTI	109.800
EEPSA	
MALACAS	**173.2**
EGENOR	
CAÑON DEL PATO	**260.730**
CARHUAQUERO	95.020
CHIMBOTE	63.833
TG PIURA	24.300
TRUJILLO	22.800
PIURA	27.850
CHICLAYO OESTE	26.610
PAITA	11.112
SULLANA	12.500
TRUPAL	15.000
ELECTROANDES	
YAUPI	108.000
OROYA	9.000
PACHACHACA	12.282
MALPASO	54.400
ELECTROPERU	
COMPLEJO MANTARO - MANTARO	798.000
COMPLEJO MANTARO-RESTITUCION	210.400
TUMBES	18.244
YARINACOCHA	**25.600**
ETEVENSA	
VENTANILLA	384
SHOUGESA	
SAN NICOLAS TV 1-2-3	**63.586**
SAN NICOLAS CUMNIS	**1.25**
EGASA	
CHARCANI	176.890
MOLLENDO MIRLESS	31.710
MOLLENDO TGM	90.000
CHILINA TV	18.000
CHILINA C.C	20.000
CHILINA SULZER	10.400
EGEMSA	
HERCA	1.020
MACHUPICCHU	92.250
DOLORESPATA	15.620
SAN GABAN	
SAN GABAN II	113.098
TINTAYA	17.960
BELLAVISTA	8.600
TAPARACHI	8.800
EGESUR	
ARICOTA	35.7
CALANA	25.6
MOQUEGUA	1
ENERSUR	
ILO 1 TV	154.000
ILO 1 TG	81.690
ILO 1 CATKATO	3.300
ILO 2 TVC1	145.000
TOTAL SEIN Inst Capacity	**4794.928**

Source: *COES* data.

The Project staff should classify *SEIN's* yearly capacity additions as follow:

Classification of SEIN Addition in Installed Capacity (MW)

Newly Built =	Only when new units are added - interconnection of units less than 5 years old are included
Interconnection =	Old unit that gets interconnected to SEIN
Rehabilitation =	Reconstruction of a plant that was broken down
Upgrade =	Same unit that increases its installed capacity by technological improvements or adjustments

Source: Own production.

Worksheet #16: Capacity Additions from 1988-2003[87]

Years	Techn	Addition Category	Install.Cap. (MW)	2001 Gen (GWh)	2002 Gen (GWh)	2003 Gen (GWh)	2004 Gen (GWh)	2011 Gen ...(GWh)	Most Recent Year Generation (GWh)
				% Inst Cap*TGen					
1988									
C.H. CARHUAQUERO	HYDRO	Newly built	75.1	469.27	479.41	458.78			
CHARCANI (I-V)	HYDRO	Newly built	136.80	842.17	641.80	660.24			
1993									
TG VENTANILLA 2	D2	Newly built	100	2.40	2.45	1.54			
TG VENTANILLA 1	D2	Newly built	100	2.40	2.45	1.54			
1995									
CALANA	R6	Newly built	19.2	33.02	25.72	45.81			
1996									
STA. ROSA WESTING	D2	Newly built	127.7	9.41	5.61	11.60			
1997									
C.H. GALLITO CIEGO	HYDRO	Newly built	34.0	183.53	149.71	121.79			
TG VENTANILLA	D2	Newly built	184.0	4.41	4.51	2.83			
MOLLENDO MIRLESS	R500	Newly built	31.7	10.98	9.53	35.37			
1998									
AGUAYTIA 1	GAS	Newly built	86.3	230.80	412.26	466.80			
AGUAYTIA 2	GAS	Newly built	86.3	216.30	332.89	367.97			
TG MALACAS	PM GAS	Newly built	102.2	206.23	181.35	274.30			
1999									
SAN GABAN II	HYDRO	Newly built	55.0	357.38	376.19	356.34			
CALANA	R6	Newly built	6.4	11.01	8.57	15.27			
MOLLENDO TGM	D2	Newly built	90.0	0.73	0.86	1.43			
2000									
SAN GABAN II	HYDRO	Newly built	58.1	377.51	397.38	376.41			
ILO2 TVC	COAL	Newly built	145.0	338.78	845.93	859.44			
C.H. CHIMAY	HYDRO	Newly built	156.0	724.76	752.96	825.87			
C.H. YANANGO	HYDRO	Newly built	42.3	214.60	239.13	202.28			
2001									
TUMBES	R6	Newly built	18.3	22.38	20.73	27.99			
2002									
C.H. HUANCHOR	HYDRO	Newly built	18.9	-	36.86	144.64			
2003									
YARINACOCHA	R6	Newly Built	25.6	-	-	56.88			
2004									
New Plants 2004				-	-	-			
2005									
New Plants 2005				-	-	-			
2006									
New Plants 2006				-	-	-			
2007									
New Plants 2007				-	-	-			
2008									
New Plants 2008				-	-	-			
2009									
New Plants 2009				-	-	-			
2010				-	-	-			
New Plants 2010				-	-	-			
2011				-	-	-			
New Plants 2011				-	-	-			

[87] Only the plants that fall in the Newly Built Classification should be considered "Capacity Addition" for the BM2 calculation

Source: Own production with *COES* data.

Only columns and rows highlighted in blue (empty low rows, empty right columns) should be updated. The year of annual generation of the capacity addition is the year of The Project generation[88]. Information of the capacity additions (MW and Technology) from 1988 through 2003 should not be recalculated but taken from Worksheet #16 (rows filled). It will be necessary to know the yearly installed capacity of the plant the unit added belongs in order to obtain the unit added participation in the total generation produced by the plant.

Worksheet #17: Build Margin 2 Calculation

Table#1: Selection of the sample group

Year	Plant Name	Plant Type	Most recent year generation(GWh)	Filter most recent 20%	Most recent 20% units generation	Filter 5 most recent units	5 Most recent units generation
2003	YARINACOCHA	r6					
2002	C.H. HUANCHOR	Hydro					
2001	TUMBES	r6					
2000	C.H. YANANGO	Hydro					
2000	C.H. CHIMAY	Hydro					
2000	ILO2 TVC	Coal					
2000	SAN GABAN II	Hydro					
1999	MOLLENDO TGM	d2					
1999	CALANA	r6					
1999	SAN GABAN II	Hydro					
1998	TG MALACAS	gas					
1998	AGUAYTIA 1	gas					
1998	AGUAYTIA 2	gas					
1997	C.H. GALLITO CIEGO	Hydro					
1997	TG VENTANILLA	d2					
1997	MOLLENDO MIRLESS	r500					
1996	TG STA. ROSA WESTINGHOUSE	d2					
1995	CALANA	r6					
1993	TG VENTANILLA 2	d2					
1993	TG VENTANILLA 1	d2					
1988	C.H. CARHUAQUERO	Hydro					
1988	CHARCANI (I-V)	Hydro					
T/.						5	
				First sample comprises:		of SEIN generation	
				SEIN Annual Gen=			
	The sample list would be composed by as it represented greater gen. addition	....		20% of SEIN Gen=			
	>						

Source: Own production.

Any new unit recorded in Worsheet#16 will origin an additional row in Worksheet #17's. In Worksheet #17, empty cells/columns highlighted in blue should be updated. New units (rows) are to be incorporated as the arrow above indicates. The first filter (5th column composed by 1s and 0s) helps keeps track that the sample's annual generation comprises the most recent 20% in generation added to the *SEIN*. The second filter (7th column) counts up to 5 most recent plants. One automatic check is included in this table; it checks whether the 5 most recent plants built's generation is greater than first sample's generation (latest 20% in generation added) and indicates which sample should be selected for the BM2 calculation.

[88] In case the addition was not an entire plant but rather a unit of an existent plant, only this new unit added to the *SEIN* should be considered in the sample. If not publicly available, its generation should be estimated by the % that this unit capacity represents in the total plant capacity times the annual generation of the plant it belongs.

Table # 2: BM2 Calculation

Clusters the generation of the selected sample by technology, and gets a tCO_2e/MWh weighted average.

Technologies in Selected Sample	Most Recent Year Gen (GWh)	% per technology	APFR	C	O	44/12	CO2 Emissions(tCO2)
Coal							
d2							
r6							
r500							
Dry Gas							
Pure Methane Gas							
Dry Gas CC							
Hydro							
Total							
BM2=	tCO2//MWh						

Source: Own production.

APFR=Annual Plant Fuel Requirement (TJ) = Gen (KWh)*3.6*10^6/(NEC*10^12); C= Carbon Content (tC/TJ); O=Oxidation Factor; 44/12= Mass Conversion (tCO_2/tC). The NECs to use in the APFR formula, and the C and O factors should be extracted accordingly from Table #3, of this Worksheet #17.

Empty columns and cells highlighted in blue should be updated. The arrow above indicate insertion of new technologies (new rows) that enter the *SEIN*.

Table # 3: NECs & IPCC 1996 values

COEF(tCO2/MWh)	Open Cycle					
Type of Fuel	D2	R6	R500	Gas Dry	Gas PM	Coal
NEC	34.93%	42.98%	32.74%	32.50%	32.50%	33.00%
C Content	20.20	21.10	21.10	15.30	14.50	25.80
Oxidation Factor	0.99	0.99	0.99	0.995	0.995	0.98
COEF(tCO2/MWh)	**0.76**	**0.64**	**0.84**	**0.62**	**0.59**	**1.01**

COEF(tCO2/MWh)	Combined Cycle				
Type of Fuel	D2	R	Gas Dry	Gas PM	Coal
NEC	55.00%	55.00%	54.00%	55.00%	55.00%
C Content	20.20	21.10	15.30	14.50	25.80
Oxidation Factor	0.990	0.990	0.995	0.995	0.980
COEF(tCO2/MWh)	**0.48**	**0.50**	**0.37**	**0.35**	**0.61**

COEF(tCO2/MWh)	Cogeneration				
Type of Fuel	D2	R	Gas Dry	Gas PM	Coal
NEC	80%	80%	80%	80%	80%
C Content	20.20	21.10	15.30	14.50	25.80
Oxidation Factor	0.990	0.990	0.995	0.995	0.980
COEF(tCO2/MWh)	**0.33**	**0.34**	**0.25**	**0.24**	**0.42**

Source: Own production with *COES* data.

Average real NECs per technology need to be calculated separately every year; Table #3, of this Worksheet #17 will show updated NECs per technology calculated with yearly real data from COES. This will allow the most accurate TJ-estimation consumed per technology. COEFs will be updated automatically as NECs are updated; both rows are linked by the following COEFs formula:
COEFs per technology = [3.6 x (44/12) x C x O] / [10^3 x NEC average per technology][89].

[89] COEFs per technology of Worksheet#1-Table#1, should be the same as COEFs gotten in this Worksheet#17-Table#3, as both use the latest information publicly available from *COES*.

Worksheet #18: Combined Margin and ERs of the year

Worksheet #18 shows the ERs of the year calculated with the 2 spreadsheets' results for DDA-OM and BM2. Empty cells highlighted in blue should be updated at the end of the year (March 31st)[90].

Project	MWh in the year
Poechos I	

Ers of the Year (DDA-OM - BM2):

Project	MWH in the year*Combined Margin
Poechos I	

DDA-OM=
BM2=
CM=

Source: Own production

V. Sustainable Development Monitoring Plan:

Being a CDM activity, The Project must meet the requirements of The Kyoto Protocol Article 12 for CDM Projects, which states that the CDM activity must assist the host country in achieving sustainable development. The Government of Peru has endorsed The Project as a CDM-eligible activity. This part of the MP explains why it can be taken for granted that The Project will contribute to environmental sustainability as well as development in Peru over its lifetime. The sustainable development objective applies also to projects, where not only positive but also negative environmental and social effects are conceivable. Therefore, the MP for The Project specifies sustainable development indicators and targets, which must be monitored and met by the Operator.

A. Environmental Sustainability: Impact on Local Pollution

In addition to mitigate emission of CO_2, The Project will reduce emissions of local pollutants (particularly SO2, NOx and particulates).

The sustainable development contribution of The Project is considered fulfilled as long as The Project is operating. Numerous environmental assessment documents were completed during the preparation phase of The Project. An EIA was completed for the hydropower project specifically, which analyzed the construction and operation phase impacts. In part due to the highly intervened surroundings, no major impacts were identified. Construction impacts were well managed through proper environmental practices, as enumerated in the Environmental Management Plan. Consideration of an ecological flow is not required, given the discussion above. A separate EIA was completed for the transmission lines, with, again, no major impacts identified.

Approximately 38 km of transmission lines that were built as part of The Project go through desert landscape with scarce vegetation. The impact of the transmission lines was thoroughly studied in a separate EIA. The EIA concluded that the line follows an existing right-of-way; it does not cross or negatively affect any populated or cultivated areas, nor areas with cultural heritage sites. As required by National Law, an architect was part of the EIA team, and the National Institute of Culture certified the EIA. The area is not a migratory bird habitat, and no impact is expected on the local bird population.

[90]Margins are rounded to the 5th decimal but the ERs of the year are rounded down to the nearest integer. The Project's generation does not need to be rounded down to the nearest integer.

The Project will operate using the current and future water requirements for irrigation, potable water and ecological flow. The total flow is determined by the local Agricultural Authority of the region, and not by The Project sponsor. The water concession is based upon the use of the flow required for agricultural needs downstream of the dam. The Project sponsors have no direct control over the flows emitted to either the Chira River or to the irrigation canal.

B. Socio-Economic Sustainability
No negative social impacts are predicted due to the remote location of The Project, and the requirement of existing water usage rights. The area of influence of The Project, including its ancillary infrastructure, is not in or near an indigenous reserve or populated area. The only population near the site is the guards of the national police that guard the dam security. No other people live near The Project site or under the transmission line. As discussed above, all water user rights will be respected, as energy generation receives a lower priority than agricultural use.

The area is extremely poor. The population downstream of the plant is small landowner farmers. The main crops are rice, plantains, vegetables and coconuts. The plant utilizes the existing access road for the dam, which passes through many of the small villages. Social impacts of construction were minimized by good construction practices such as traffic control, noise reduction, and proper waste disposal. Many jobs were created during construction and now during operation.

A broader social program involves providing the local communities with access to electricity, something most of the nearby communities live without. The new transmission line has opened up the possibility of electrification in the area. The distribution of electricity is the sole right and responsibility of the Department of Energy and Mines; the sponsor is not allowed to undertake a social electrification program itself. However, the sponsor is working with the Department of Energy and Mines to promote this program in the area. So far, The Project has installed a keys yard of 22.9 Kv to feed 3 small isolated systems: the Lancones system, the Chira system, and the third one goes into a small population located close to the Ecuadorian border. These three small populations' consumptions will be partly "subsidized" by the Peruvian Government according to The Department of Energy and Mines overall initiative regarding social development and rural electrification: *FOSE*[91] and Rural Electrification Plan, respectively.

VI. Management and Operational Systems Monitoring Plan
A. Purpose
It is the responsibility of the Operator to develop and implement a management and operational system that meets the requirements of The Project and of the MP. Equally, it is the Operator's responsibility to enter into appropriate agreements with local institutions (i.e. *COES*) and final clients (ENOSA), to secure an adequate data gathering, processing and recording. The operational and management system shall include, among others Data Handling.

B. 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 Operator must develop and implement a protocol that provides for these critical functions and processes, which must be ready for independent auditing.
-For electronic-based and paper-based data entry and recording systems, there must be clarity in terms of the procedures and protocols for collection and entry of data, usage of the spreadsheets and any

[91] *Fondo de Compensacion Social Electrica* – was created by Law 27510 in 2001. Currently FOSE's life is set until December 2006. The FOSE was created to favor electricity access and permanency of it to all clients that consume less than 1000 KWh, by providing them discounts.

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 systems failures.

C. Quality assurance:
-Well-defined protocols and routine procedures, with good, professional data entry, extraction and reporting procedures will reduce costs and time while making it considerably easier for the auditor and verifier to do their work - the more organized and transparent the organization, the easier will be to track, monitor, audit and verify.
-The Operator must keep proper management processes and systems records, as the auditors will request copies of such records to check compliance with the required management systems. Auditors will accept only one set of official information, and any discrepancies between the official, signed records and on-site records will be questioned.

D. Reporting:
-The Operator will report regularly to The NCDMF as well as to Peruvian authorities as required.
-The Operator will prepare reports, as needed for audit and verification purposes.

E. Training:
-It is the Operator´ responsibility to ensure that the required capacity and internal training is made available to assigned The Project Staff, to enable them to undertake the tasks required by this MP. NCDMF will train the Project Staff on the tasks needed to observe the present MP.

F. Preparation for Operation:
-The management and operational systems and the capacity to implement this MP must be put in place before The Project can start generating ERs or by the end of the first year of the first crediting period. This will be verified before any Project can start to generate ERs that are accepted by The NCDMF.

VII. Auditing and Verification Procedures

A. Audit and Verification Objectives

Periodic auditing and verification of The Project's results is a mandatory component for all CDM Projects and a NCDMF requirement. The chief objective of the audit is to independently verify that The Project has achieved the ERs reported by the Operator. Audits are an integral part of the verification process and are undertaken in conjunction with verification and by the same firm.
This section of the MP outlines the auditing and verification procedures and prerequisites. It provides instructions on how the monitoring work undertaken by the Operator is in line with the MP; as well as project performance and compliance with 14CDM requirements that need to be verified. The NCDMF will select and contract the Verifier.

B. The Netherlands Carbon Facility Audit and Verification Regime

The NCDMF submits The Project to third party validation and verification, which is conducted by independent firms specializing in environmental auditing services (auditors, validator, verifiers, and certifiers). The NCDMF expects that its auditors will seek accreditation under The Kyoto Protocol regime for providing these services. The NCDMF verification system for CDM consists of four activities:

Validation of project design: the Validator undergoes validation of The Project's design, the BLS and the MP against CDM requirements and modalities and is complemented by validation of The Project. Validation is a CDM requirement. The NCDMF will not sign contract with The Project unless a Validator has confirmed that The Project design is in compliance with all relevant CDM requirements. The validated MP for a project must be followed by the Operator and any other involved partner. This

MP can be adjusted or amended, if necessary, in order to improve consistency with its objectives, general concepts and project circumstances, but such adjustments are subject to approval by The Project Verifier. A renewal of validation is not necessary in this case.

Initial audit and verification of project readiness: The NCDMF requires that The Project successfully complete an initial audit and verification process before The NCDMF commissions The Project and accept emissions reductions delivered by it. While initial verification is not a CDM requirement, The NCDMF regards it as essential and final step in The NCDMF project preparation and implementation cycle. To prevent conflicts of interest, the same firm and individuals that have provided validation services for The Project must not conduct verification. But the initial auditor / verifier may also provide subsequent verification services to The Project. Initial verification provides an opportunity for verifiers to become familiar with The Project, its context, the Operator and its management.

The purpose of the initial audit and verification process is threefold:
1. Ensure that The Project has been implemented as planned, that the monitoring system is in place and that The Project is ready to generate and record GHG emissions reductions.
2. Ensure the correct meters and registers are installed and tested.
3. Approve adjustments and amendments to the MP that may have become necessary during the detailed design and construction of The Project.
4. Assist meeting The NCDMF supervision obligations and clear the way for project commissioning and generation of high quality ERs.

During initial verification, auditors are expected to do the following. They will:
5. Familiarize themselves with The Project and The Project circumstances,
6. Introduce The Project Staff to the audit and verification process,
7. Check whether The Project has been implemented as planned,
8. Check whether the meters and registers have been installed and tested correctly and are in operation.
9. Check whether assumptions that have an impact on the monitoring and verification processes and its outcomes are still reasonable, in particular assumptions for the BL.
10. Confirm system readiness: that the MP has been implemented in The Project's management and operational procedures and that all necessary monitoring elements are in place to ensure generation of verifiable emissions reductions.

Periodic verification of ERs: All NCDMF Projects must undergo periodic audits and verification of ERs. This is a CDM requirement and the basis for issuance of Certified Emissions Reductions (CER) and for their value in the market place. Verification is arranged by The NCDMF and conducted at annual or longer intervals as appropriate for The Project.
The purpose of periodic audits and verification is to confirm that:
1. The Project has achieved the ERs claim for the verification period in compliance with the methodology laid down in this MP.
2. The claimed ERs are real and additional to any that would have occurred in the Baseline Scenario as interpreted and developed in the BLS and this MP.
3. The operation of The Project continues to be in compliance with all Kyoto Protocol, NCDMF and host country requirements and modalities for CDM Project.
4. The Project maintains high quality monitoring systems consistent with the MP.

As part of the periodic audit and verification process auditors are expected to:
1. Review and audit relevant monitoring records and reports.

2. Verify that the required measurements and observations made for all data inputs necessary for the calculation of ER, are available.
3. Check that meters and recorders are operating correctly.
4. Check whether the MP methodology has been applied correctly and consistently.
5. Check whether achieved ERs have been computed correctly using the provided spreadsheets, and, if necessary, recalculate achieved ERs.
6. Verify that all relevant MP and BLS assumptions are still valid.
7. Verify that the management and monitoring system, including data handling, recording and reporting, are in place and remain adequate.
8. Verify that the social and environmental targets in the MP have been met and that The Project assists the host country in achieving sustainable development.
9. Consult with the Operator and other project partners on the continued adequacy of the monitoring system and approve any modifications that need to be made to ensure a high quality monitoring operation.
10. Undertake any other activities required by this MP, by The Kyoto Protocol requirements and modalities for the CDM, by the appropriate host country authorities and/or by professional auditing and verification standards and practice.

Verification concludes with a formal verification report. The report may include a statement that may permit the renewal of The Project's crediting period in line with applicable CDM rules and modalities.

Certification of ERs: A successfully completed verification process and related verification report provide the basis for the issuance by the Verifier of an emissions reductions certificate. The certificate is a legally binding statement, which confirms the (successful) verification report's conclusion that The Project has achieved the stated quantity of ERs in compliance with all relevant criteria and requirements. The Verifier's certificate constitutes sufficient confirmation for The NCDMF as to The Project's emissions reductions performance.
The Verifier for The Project is the only one that can issue the certificate but it does not constitute or creates Certified Emissions Reductions (CER) in the sense of Article 12 of The Kyoto Protocol. However, the Verifier's certificate may be used by The NCDMF and/or Peruvian authorities or authorized entities in the process of issuance and registration of CERs by the competent authority in line with applicable CDM and Kyoto Protocol modalities and procedures.

C. Auditing Criteria and Needs
Verification includes an audit of The Project's output information, and data and management systems on the basis of the following established criteria:
1. Completeness
2. Accuracy
3. Coverage
4. Risk Management Controls

Auditors and verifiers will request information (in the form of records and documentation) from the Operator to determine if key performance indicators meet the objectives of The Project as set out in this document. The Operator is required to record all such indicators, and provide satisfactory documentation and an audit trail for verification purposes (for instance, generation and sales records, etc.). The information that will be needed includes:
1. Records on reported GHG emissions reductions including the electronic worksheets and supporting documentation (assumptions, data estimations, measurement methods, etc).
2. Records on reported social and environmental performance as measured by indicators and targets laid down in The Project MP

3. Records on project management, including monitoring, data collection and management systems.

The audit process followed, as with other management systems, is interactive, iterative and participatory. The auditors will determine the credibility and accuracy of the reported performance through spot checks of data measurement and collection systems and interviews with the key project participants. It is necessary for all involved in an audit to understand the audit process and verification requirements.

D. Audit and Verification Process

Audits procedures used to verify CDM Project are similar to audits of other environmental management systems (ISO 14000, EMS) and should complement these established processes. Principle audit tools are spot check of documents and interview with participating organizations and individuals. Auditors/verifiers are generally free to apply any method that represents good auditing practice and internationally accepted standards. Auditors typically conduct risk-based spot checks, which are checks of the key parameters and systems with the highest risks for data measurement and collection problems. The planning and scheduling of audits and the verification process is covered in this section.

Audit preparation and requests for information: The auditor will familiarize himself with The Project documentation, project reports, project requirements and expected project performance. The auditor will use this MP to prepare the audit process. He will make telephone contact with the Operator, and if necessary, will request additional information. Two weeks should be allowed for the receipt of this information.

Development and delivery of an audit checklist: The auditor will develop checklists to guide the audit process. The checklists will cover the key points of the audit. The appropriate checklist will be sent to the Operator accompanied by explanatory materials prior to a site visit. Two weeks should be allowed for review, comments and preparation by the Auditee.

The Audit: A visit will be made to the site to undertake the audit. The length of the audit visit is to be agreed between the auditor and NCDMF and depends on the complexity of the monitoring system and on previous performance based on experience. Audits on each site do normally not require more than two days. The audit time will be spent checking records and undertaking interviews with staff and other individual, which will allow the auditor to complete the audit checklist. These activities are the basis for completing the verification process and for preparing the verification report.

Audit and draft verification reports: The auditor will produce an audit report and a draft verification report for The Project, which summarizes the audit findings. The draft verification report will state the number of ERs achieved by The Project and will point to areas of possible non-compliance if warranted. The report will also include conclusions on data quality, the monitoring and management and operational system, and other areas where corrective action may be required to come into compliance, improve performance or mitigate risks. The draft report will be submitted to The NCDMF, and a copy will be sent to the Operator. The Project will have the opportunity to come into compliance, if necessary, by submitting the appropriate evidence or by taking corrective action.

Final verification report: The auditor will revise the draft report taking into consideration reviewers' comments and further findings and issue the final verification report, if possible within two weeks of receiving all comments. If justified, the final verification report will conclude and explain that, within the verification period, The Project has generated the stated quantity of ERs in compliance with all applicable CDM and other requirements. The final verification report is the basis for the issuance of a certificate by the Verifier, which will state and confirm the conclusions of the report.

Non-compliance and dispute settlement: In the event of non-compliance findings, the non-complying Auditee will be given sufficient time to demonstrate compliance. An eight week period from the issuance of the draft report is recommended for the Auditee to address identified deficiencies and come into compliance. It is the responsibility of the Verifier to ensure that dispute over any non-compliance issue is communicated clearly and that any attempt is made to resolve it. The Verifier will have final decision over the process. The Verifier will also provide guidance as appropriate on how identified deficiencies can be met so that the Operator can come into compliance in the following period.

Audit and verification schedule: Audits and verification of The Project will be conducted annually at first, then at intervals over the life of The Project. The NCDMF in consultation with auditors and the Operator will determine the audit schedule. Audit intervals will depend on audit outcomes and experience with The Project performance and compliance with the MP, the quality of its monitoring management and operational systems, and the type and number of corrective actions required by the Verifier.

E. Roles and Responsibilities
Audit responsibilities are allocated between The Project participants as follows:

The NCDMF:
1. The NCDMF will make arrangements for the audit and select a third party auditor/verifier in accordance with CDM modalities and NCDMF requirements and selection criteria and in consultation with the relevant the host country CDM authority.
2. It is The NCDMF's obligation to ensure that the audit process is fair, that the auditor/verifier is fully independent of the Operator and that and all possible conflicts of interests are avoided. The NCDMF requires details of the experts to be used on the audit/verification team.
3. The NCDMF will facilitate the audit work and verification process and will work with The Project participants to ensure co-operation.

The Operator:
1. Will prepare for the audit and verification process to the best of its abilities.
2. Will facilitate the audit through providing auditors with all the required information, before, during and, in the event of queries, after the audit.
3. Will fully cooperate with the auditors and instruct staff and management to be available for interviews and respond honestly to all audit questions.
4. It is the contractual obligation of the Operator and in their best interest to fully cooperate with auditors and verifiers, since only successful verification will enable the delivery of ER to The NCDMF in fulfillment of the Operator' contracts with The NCDMF.

The Auditor / Verifier:
1. The auditors/verifiers must be must operational entities accredited in accordance with CDM modalities. They must be a professional organization with a proven track record in environmental auditing and verification, experience with CDM Project and work in developing countries. The audit firm must guarantee professional work and assure the quality of the audit and verification team.

2. The auditors / verifiers must undertake the audit to the best of their professional abilities. The auditor's responsibilities include to (a) provide the checklists and request for information in good time, (b) allow adequate time for sufficient review and preparation, (c) provide publishable reports in the agreed format, (d) work with the Operator, host country authorities and NCDMF as appropriate, (e) report on lessons learnt during the course of The Project.

VIII. Annexes

Sustainable Development Monitoring Plan (SDMP)

The SDMP will cover The Project's direct[92] and indirect[93] area of influence and their habitants. A Sustainable Development Indicators & Targets framework will facilitate the measurement of progress towards sustainability. The indicators will be revised annually[94] by the Verifier to check compliance with targets. The Targets will be progresses[95] registered by the indicators. The following indicators have been established:

Goal 1: Environmental Sustainability		
Initiative	**Indicator[96]**	**Target**
Land Quality improvement	Number of trees sowed	Positive
Awareness	Number of environmental educational programs for local population[97] (i.e. energy savings, water savings, etc.)	Positive
New Initiative	In case The Sponsor desires to incorporate a new initiative to this Environmental-Sustainability-initiative list, it will have to be approved by the Verifier	N/A[98]

Goal 2: Socio-Economic Sustainability		
Initiative	**Indicator[99]**	**Target**
Education standards improvement	Grants provided for education of local population	Positive
Economic standards improvement	Number of employees hired from local population	Positive
	Purchases from local suppliers	Positive
	[Population that accesses electricity due to The Project's action or cooperation] Divided by [viable opportunities[100] on rural electrification proposed to The Project by third parties or identified by The Project management]	Positive
New Initiative	In case The Sponsor desires to incorporate a new initiative to this Socio-Economic-Sustainability-initiative list, it will have to be approved by the Verifier	N/A[101]

To provide evidence of listed indicators' progresses, The Project should provide the Verifier the following:
(a) Receipts of expenses incurred for the socially and environmentally responsible action

[92] Approximately 3.5 hectares (defined by the *MINEM* concession granted).
[93] Approximately 6 hectares (defined in the EIA).
[94] The year for the MP runs from April 1st to March 31st.
[95] Progresses meaning positive results of the indicators.
[96] Yearly flow or yearly change.
[97] Local meaning people who are living in the direct or indirect area of influence for reasons other than The Project occurrence.
[98] Target will be set when indicator is created and also needs to be approved by the Verifier.
[99] Yearly flow or yearly change.
[100] Viable opportunities meaning positive Net Present Value projects.
[101] Target will be set when indicator is created and also needs to be approved by the Verifier.

(b) Documents related to socially and environmentally responsible action.
(c) The Compliance Form signed bi-annually by all members of the Compliance Committee (described below).

The Compliance Committee:
The Compliance Committee will be formed to enforce further the SDMP.

The Compliance Committee will be composed by a representative from:
- Universidad-de-Piura: PhD. Ignacio Benavente, who is a member of the faculty; and
- The area of Influence: Isais Vazquez Moran, Sullana City Mayor

The Compliance Committee will meet bi-annually to:
- After reviewing evidence [(a) and (b) described above], reviewing a written summary of the environmentally and socially responsible actions taken in the semester - to be prepared by The Project Sponsor (SINERSA) - and being left convinced by this evidence about the indicators' progresses' accuracy claimed by The Project, sign the attached form annexed below ("Compliance Form"); and
- Review progresses, identify stoppages and suggest solutions regarding listed indicators, to SINERSA, legally represented by Mr. Branislav Zdravkovic, who will be present at the meeting.

Bi-annual Compliance Committee Meeting - Compliance Form

Goal 1: Environmental Sustainability		
Initiative	**Indicator[102]**	**Annual Cumulative Progress**
Land Quality improvement	Number of trees sowed	Of 1rst Semester = Of 2nd Semester =___________ **As of March 31st =**
Awareness	Number of environmental educational programs for local population[103] (i.e. energy savings, water savings, etc.)	Of 1rst Semester = Of 2nd Semester =___________ **As of March 31st =**
New Initiative	In case The Sponsor desires to incorporate a new initiative to this Environmental-Sustainability-initiative list, it will have to be approved by the Verifier	N/A[104]

Goal 2: Socio-Economic Sustainability		
Initiative	**Indicator[105]**	**Annual Cumulative Progress**
Education standards improvement	Grants provided for education of local population	Of 1rst Semester = Of 2nd Semester =___________ **As of March 31st =**
Economic standards improvement	Number of employees hired from local population	Of 1rst Semester = Of 2nd Semester =___________ **As of March 31st =**
	Purchases from local suppliers	Of 1rst Semester = Of 2nd Semester =___________ **As of March 31st =**
	[Population that accesses electricity due to The Project's action or cooperation] Divided by [viable opportunities[106] on rural electrification proposed to The Project by third parties or identified by The Project management]	Of 1rst Semester = Of 2nd Semester =___________ **As of March 31st =**
New Initiative	In case The Sponsor desires to incorporate a new initiative to this Socio-Economic-Sustainability-initiative list, it will have to be approved by the Verifier	N/A[107]

Identified stoppages, suggested solutions and other observations brought up in the meeting: _________
____
____
____(Annex extra-paper if necessary).

____________________________ ____________________________
Universidad de Piura Representative The Project's Area of Influence Representative

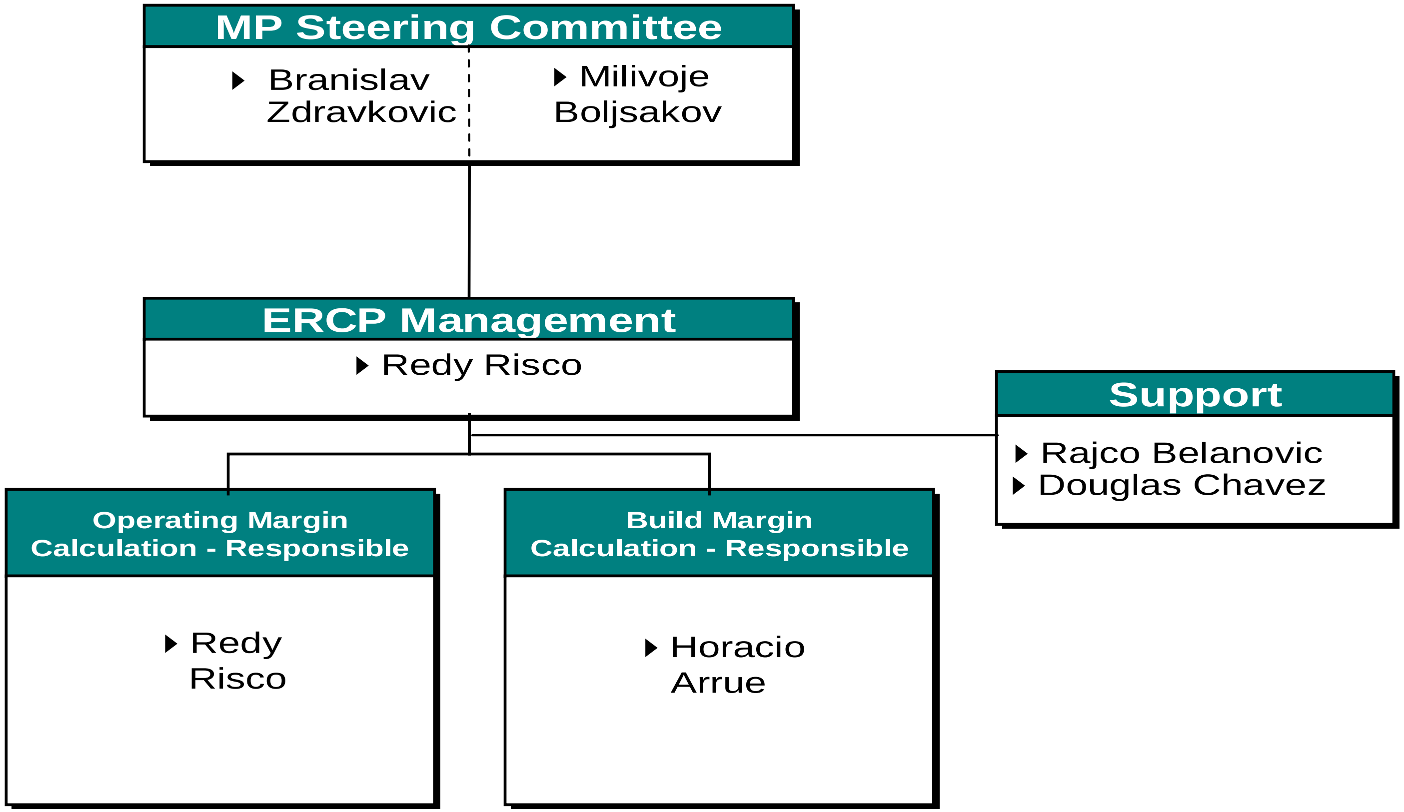
____
The Sponsor

[102] Yearly flow or yearly change.
[103] Local meaning people who are living in the direct or indirect area of influence for reasons other than The Project occurrence.
[104] Target will be set when indicator is created and also needs to be approved by the Verifier.
[105] Yearly flow or yearly change.
[106] Viable opportunities meaning positive Net Present Value projects.
[107] Target will be set when indicator is created and also needs to be approved by the Verifier.

Date of the Compliance Committee Meeting:

Monitoring Plan (MP) – Emissions Reductions Calculation Procedure

ERCP Organizational Structure



Monitoring Plan (MP) – Emissions Reductions Calculation Procedure

ERCP Quality Control

Operating Margin Calculation ⟷ **Build Margin Calculation**

- *Quarterly Cross-checking*
- *Quarterly Corrective actions*
- *Check calibration of electricity meters, periodically*
- *Make coordination with ENOSA and COES to be able to implement this document*

Data

Operating Margin Calculation

- The Project hourly generation data: "A"
- *SEIN* units hourly generation data: "B"
- Weekly Merit order for hours of maximum demand: "C"
- Real NEC per power plant of the *SEIN*

Build Margin Calculation

- *COES* most recent year operations statistics (Tables: 2.6, 4.3, 12.1): "D"
- New units that enter the SEIN from Jan 1st to March 31st: "E"
- Real NEC per power plant of the *SEIN*

Quality of Data Collection

Operating Margin Calculation

- Which data comes? All of the above
- By what means does it come? By E-mail/ CD
- How does it come? In Excel
- How frequently does it come? Monthly
- From whom does it come? A from *ENOSA;* B-C *COES(Programacion Semanal)*
- To whom does it comes? Ing. Risco & Ing. Arrue

Build Margin Calculation

- Which data comes? All of the above
- By what means does it come? By E-mail/ CD
- How does it come? In Excel
- How frequently does it come? Yearly
- From who does it come? From *COES* (EE. Economicos)
- To whom does it comes? Ing. Risco & Ing. Arrue

Quality of Data Processing

Operating Margin Calculation

- Original Data
- Organized Data
- Entered Data
- Processed Data
- Result

  - Monthly calculation involves 5 steps
  - Follow ERCP
  - Beware of alerts – presented in training
  - Quarterly cross-check by BM responsible
  - Yearly consolidation of C.Margin

Build Margin Calculation

- Original Data
- Organized Data
- Entered Data
- Processed Data
- Result

  - Yearly calculation involves 5 steps
  - Follow ERCP
  - Beware of alerts – presented in training
  - Yearly c-check by OM responsible
  - Yearly consolidation of C.Margin

Quality of Data Storage

- Prevent Excel versioning problem, by keeping "a new" Excel software package every year in PCs used for the OM and BM calculations
- Keep all data for 2 years after the first crediting period (9 years) –Each responsible should assign a password to his excel spreadsheets
- Save the document with the last date in which an alteration was made, i.e. "OM at xx", so that old versions are kept in disk
- Keep all written documentation in a folder per Margin/Responsible

Quality of Data Delivery

- Provide to the Verifier e-mails /CD through which Data Providers (COES and ENOSA) delivered the original data
- Provide to the Verifier receipt of sales of ENOSA
- Provide to the Verifier all calculations made (all steps of Data Processing) by showing all preliminary versions of spreadsheets saved in disk