	Project design document form **(Version 11.0)**
Complete this form in accordance with the instructions attached at the end of this form.	
BASIC INFORMATION	
Title of the project activity	8 de Agosto
Scale of the project activity	☒ Large-scale ☐ Small-scale
Version number of the PDD	4.5
Completion date of the PDD	21/05/2021
Project participants	Generacion Andina S.A.C.
Host Party	Peru
Applied methodologies and standardized baselines	ACM0002 (Version 13.0.0)
Sectoral scopes	1
Estimated amount of annual average GHG emission reductions	105,133

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

>>

8 de Agosto (the Project) is a run-of-river hydro power plant located at the river Aucantagua which is a tributary to the Monzón River. The Project is located in the Monzón district, Huamalie province, Huánuco department. The Project shall be implemented by the special purpose company named Generación Andina S.A.C. which is owned by Polaris Energy Perú Corp.

The purpose of the Project is to generate electricity using renewable energy sources to be supplied to Peru's National Interconnected Electric Grid (hereafter referred to as the SEIN). The reduction of the baseline emissions results from the displacement of electricity generated by the power plants that form part of the Peruvian electricity system SEIN, which include fossil-fuel based power plants emitting CO2. The Project's total installed generating capacity is 20.576 MW, with an expected annual net electricity generation of 159,442 MWh. It is expected that the Project will be commissioned 31/12/2014.

As per the applicable methodology, the project activity is the installation of a new grid-connected renewable power plant/unit, the baseline scenario is electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin. The emission sources and gases included are none for the project activity (as per the applicable methodology) and CO2 emissions from the current fuel mix in the grid in the baseline.

The Project's design flow is given with 18 cubic meters per second (m^3/sec). The intake will be located at the Aucantagua river. The water shall be led through a 3,040 meter long channel and afterwards through a 894 meter long tunnel. The penstock of 240 meter will carry the water to the powerhouse. The net head is given with 128 meter. The powerhouse shall host two Francis turbines. The water shall be discharged to the Monzón River.

The Project start date is estimated to be the 28/02/2013 in accordance with the current working schedule of the project developers. At this date it is estimated to reach financial closing of the Project. The initial investment analysis is conducted as of 30/09/2011, when a power purchase agreement (PPA) has been signed as part of the renewable energies (RER) auction conducted in Peru. The contract signature required the issuance of a performance bond with 100,000 USD/MW.

The Project is expected to displace 735,931 tons of carbon dioxide equivalents (tCO2e) in the first 7 years lasting crediting period, generating an equivalent amount of Certified Emission Reductions (CERs).

The spatial extent of the project boundary is the SEIN. The generated electricity will be supplied to the SEIN through a 58.67 km transmission line at a 138 kV level to the Tingo Maria substation.

The Project will contribute to sustainable development by:

a) Creating a source of renewable energy in a sustainable way;

b) Helping the SEIN to reduce the utilization of thermal power plants for power

generation, thus displacing displacing expensive thermal generation, while at the same time reducing GHG emissions;

c) Employing local labor in construction and plant management.

d) Supporting local development (see section E.3)

e) Adding revenue to Peru's fiscal accounts through the payment of taxes; and

f) Helping Peru improve its hydrocarbon trade balance through reduction of oil imports in electricity generation.

A.2. Location of project activity

>>

The Project is a run-of-river hydro power plant located at the river Aucantagua which is a tributary to the Monzón River. The Project is located in the Monzón district, Huamalie province, Huánuco department. The project is approximately 70 km away from the city of Tingo María and 1.8 km away from the village of Maravillas.

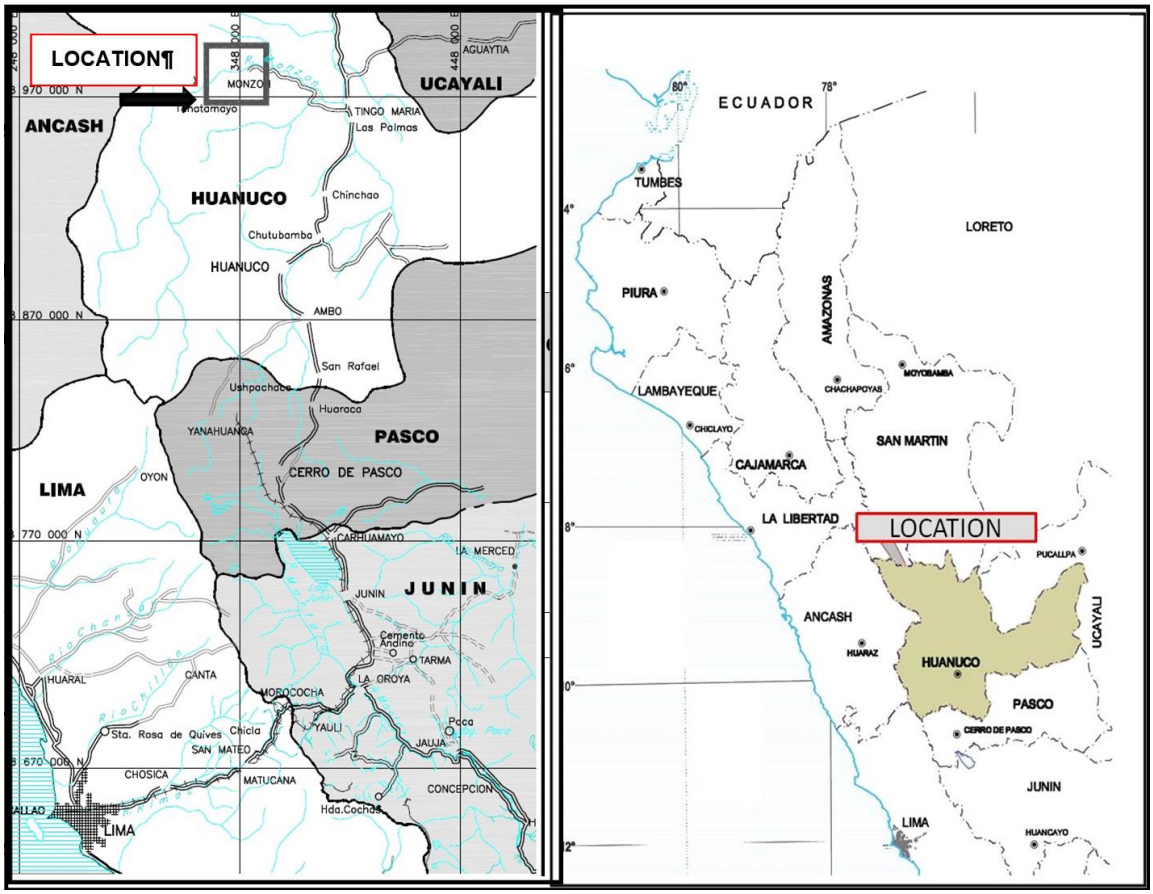
The Project's geographic coordinates for the powerhouse are given as follows:[1]

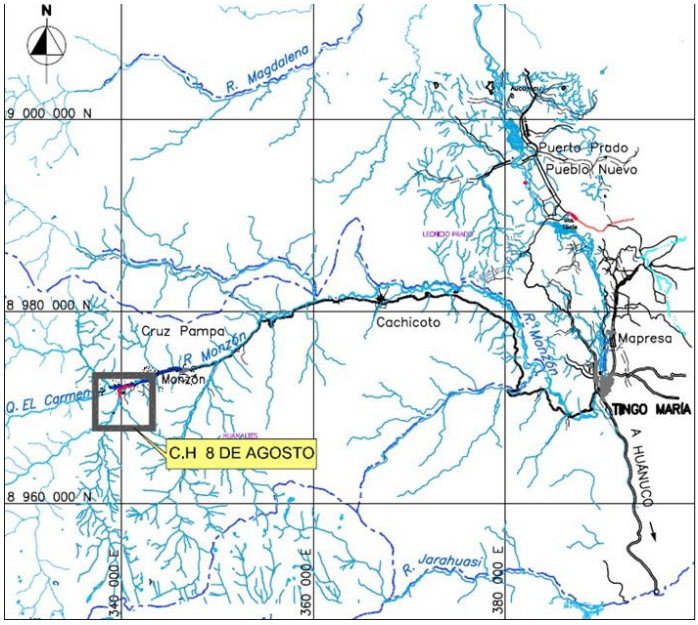
	Longitude	Latitude	(meters above sea level-masl).
Powerhouse	-76.355736	-9.294698	1,045.00

The location of the Project can be seen in the figure below:

[1] The coordinates are approved in the Directorial Resolution Nr. 0142-2011-ANA-DARH granted by the Peruvian Water Authority on 16/09/2011. Thereby the coordinates are given in WGS 84 UTM and are 8972282 N; 351095 E originally.

Figure 1: Map of the Project Locaton





A.3. Technologies/measures

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The technology employed is based on conventional run-of-river hydropower generation technology, consisting of horizontal Francis turbines that are widely used all over the world. The Project will transfer environmentally safe technology and know-how to Peru by bringing knowledge, equipment and designs of modern renewable hydroelectric technologies.

The Project's design flow is given with 18 cubic meters per second (m^3/sec). The intake will be located at the Aucantagua river. The water shall be led through a 3,040 meter long channel and afterwards through a 894 meter long tunnel. The penstock of 240 meter will carry the water to the powerhouse. The net head is given with 128 meter. The powerhouse shall host two Francis turbines. The water shall be discharged to the Monzón River.

The spatial extent of the project boundary is the SEIN. The generated electricity will be generated at 13.8 kV, which will be stepped up to 138 kV and transmitted through a 58.67 km transmission line to the Tingo Maria substation.

The project has started commercial operation on December 25th 2019.

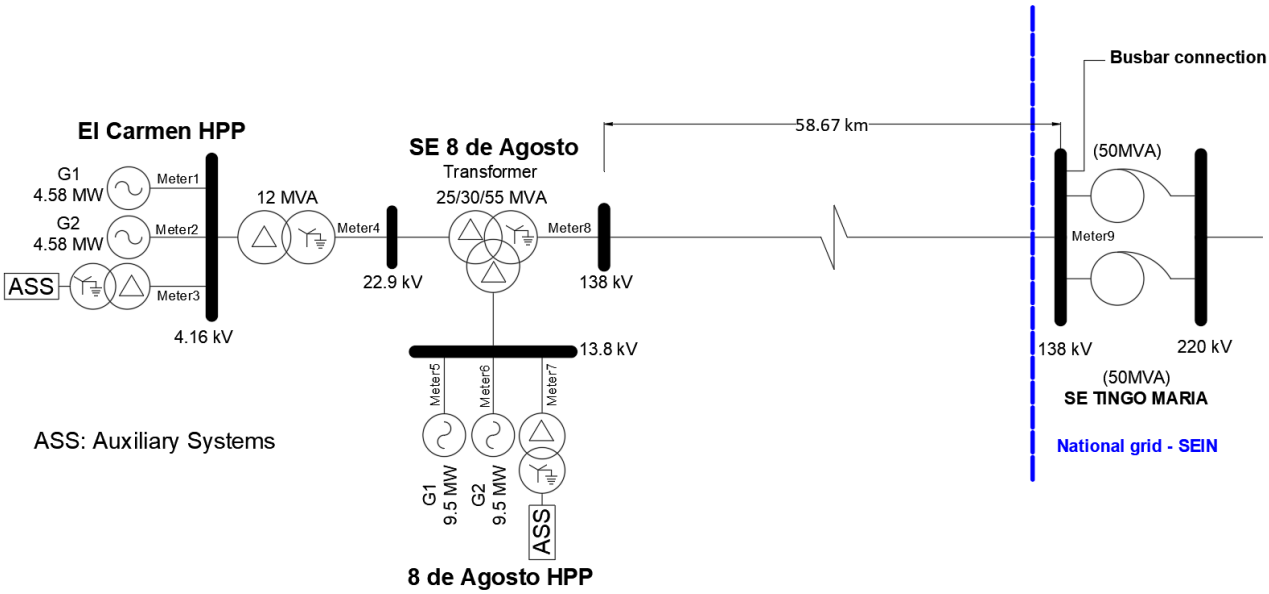
The technological characteristics of the Project are described in the following table.

Table 1: Technological Characteristics

Main parameters	Values

Design discharge :	18 m^3/s
Generating power capacity nominal:	20.576 MW
Power capacity of each generator	10,288 kW
Power Factor	0.9
Number of turbines employed	2
Power capacity of each turbine	10,623 kW
Expected net energy generation per year supplied to the SEIN:	159,442 MWh
Turbine type	Two Francis turbines of horizontal axis
Net load factor	90 %
Transmission losses	1.67 %
Turbine rated net head	128 m
Water Channel	3,040 m
Water Tunnel	894 m
Penstock	240 m
Average lifetime of electromechanical equipment	30 years
Transmission Line	Voltage level 138 kV, 58.67 km from the power house to Tingo Maria substation.
Measurement equipment	The electric meters will be implemented according to the dispatch center (COES) requisites[2],which currently requires that the metering system shall be at least Class 0.2 compliant in metering accuracy.

[2] See: Technical Procedure of the Committee of Economic Operation of SINAC- PR – 20 Verification of Compliance with Requirements for being a member of COES SINAC, p. 20; in the internet: http://www.coes.org.pe/coes/Procedimientos/procedimiento_n20.pdf; web linked accessed 09/11/11.



Net energy to the grid connection

The Project will generate energy at a 13.8 kV level, which is going to be stepped up to a 138 kV level at the Project's substation. A transmission line of 58.67 km length will conduct the electricity to Tingo Maria busbar (bidirectional meter location), which is connected to the national grid (SEIN).

In total four meters will be employed at the power plant and one meter at the Tingo Maria substation. one meter is placed at each generator and one is used for the auxiliary consumption – all measuring at 13.8 kV. Another meter is placed at the "8 de Agosto" substation measuring after uplifting to the transmission tension of 138 kV. Another meter is in place at the "Tingo Maria" substation, which does not have any significance for the project activity.

A.4. Parties and project participants

Parties involved	Project participants	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Peru	Generación Andina S.A.C.	No

A.5. Public funding of project activity

>>
Not applicable

A.6. History of project activity

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It is confirmed that the project activity has neither been registered as a CDM project activity nor included as a component project activity (CPA) in a registered CDM programme of activities (PoA). The project has not been a deregistered project activity before.
It is further declared that the project was not a CPA that has been excluded from a registered CDM PoA or that a registered CDM project activity or a CPA under a registered CDM PoA whose crediting period has or has not expired (hereinafter referred to as former project) exists in the same geographical location as the proposed CDM project activity.

A.7. Debundling

>>

Not applicable.

SECTION B. Application of methodologies and standardized baselines

B.1. References to methodologies and standardized baselines

>>

Version 13.0.0 EB 67 of ACM0002, "Consolidated baseline methodology for grid-connected electricity generation from renewable sources" (herein referred to as the Baseline Methodology) was applied to the project activity. The Baseline Methodology will be used in conjunction with the approved monitoring methodology ACM0002 (the Monitoring Methodology).

For more information regarding the methodology, please refer to the link:

http://cdm.unfccc.int/methodologies/DB/UB3431UT9I5KN2MUL2FGZXZ6CV71LT

This methodology also refers to the approved versions of the following tools:

- Tool to calculate the emission factor for an electricity system (Version 02.2.1 EB 63)

For more information regarding the methodology, please refer to the link:
http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v2.2.1.pdf/history_view

- Tool for the demonstration and assessment of additionality (Version 06.0.0 EB 65).

For more information regarding the methodology, please refer to the link:
http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-01-v6.0.0.pdf

B.2. Applicability of methodologies and standardized baselines

>>

This Project satisfies the applicable conditions of ACM0002 because the project activity has the purpose to implement a new grid connected renewable power plant at a site where no renewable

power plant was operated prior to the implementation of the project activity (greenfield plant). The applicability conditions are described in the table below:

Table 2: Applicability of ACM002 and the Proposed Project Description of ACM0002

Description of ACM0002	The Proposed Project
The project activity is the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydro power plant/unit (either with a run-of-river reservoir or an accumulation reservoir), wind power plant/unit, geothermal power plant/unit, solar power plant/unit, wave power plant/unit or tidal power plant/unit;	Applicable The proposed project activity is the installation of a hydro power plant with a run-of-river reservoir.
In the case of capacity additions, retrofits or replacements: the existing plant started commercial operation prior to the start of a minimum historical reference period of five years, used for the calculation of baseline emissions and defined in the baseline emission section, and no capacity expansion or retrofit of the plant has been undertaken between the start of this minimum historical reference period and the implementation of the project activity	Not applicable No capacity additions, retrofits or replacements are implemented in the proposed project.
In case of hydro power plants: • One of the following conditions must apply: o The project activity is implemented in an existing single or multiple reservoirs, with no change in the volume of any of reservoirs; or o The project activity is implemented in an existing single or multiple reservoirs, where the volume of any of reservoirs is increased and the power density of each reservoir, as per the definitions given in the Project Emissions section, is greater than 4 W/m^2; or o The project activity results in new single or multiple reservoirs and the power density of each reservoir, as per the definitions given in the Project Emissions section, is greater than 4 W/m^2. In case of hydro power plants using multiple reservoirs where the power density of any of the reservoirs is lower than 4 W/m^2 all the following conditions must apply: • The power density calculated for the entire project activity using equation 5[3] is greater than 4 W/m^2;	Applicable The proposed project activity results in new reservoirs and the power density[5] of the power plant is 87,963 (19,000,000W/216 m^2) W/m^2 greater than 4 W/m^2.

[3] Equation 5 of the methodology ACM0002

• Multiple reservoirs and hydro power plants located at the same river and where are designed together to function as an integrated project[4] that collectively constitute the generation capacity of the combined power plant; • Water flow between multiple reservoirs is not used by any other hydropower unit which is not a part of the project activity; • Total installed capacity of the power units, which are driven using water from the reservoirs with power density lower than 4 W/m^2, is lower than 15 MW; Total installed capacity of the power units, which are driven using water from reservoirs with power density lower than 4 W/m^2, is less than 10% of the total installed capacity of the project activity from multiple reservoirs.	
The methodology is not applicable to the following: • Project activities that involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site; • Biomass fired power plants; Hydro power plant that results in the creation of a new single reservoir or in the increase in an existing single reservoir where the power density of the power plant is less than 4 W/m^2.	Not applicable
In the case of retrofits, replacements, or capacity additions, this methodology is only applicable if the most plausible baseline scenario, as a result of the identification of baseline scenario, is "the continuation of the current situation, i.e. to use the power generation equipment that was already in use prior to the implementation of the project activity and undertaking business as usual maintenance".	Not applicable The proposed project does not involve retrofits, replacements, or capacity additions.

Therefore, the baseline methodology ACM0002 is applicable to the project activity. In addition, the applicability conditions included in the tools used apply.

- Tool to calculate the emission factor for an electricity system (Version 02.2.1 EB 63) is applied to calculate baseline emissions for a project activity that substitutes grid electricity. Under this tool, the emission factor for the project electricity system can be calculated either

[5] Power density is defined as installed power generation capacity divided by the surface area at full reservoir level.

[4] This requirement can be demonstrated, for example, (i) by the fact that water flow from upstream power units spilling directly to the downstream reservoir, or (ii) through the analysis of the water balance. Water balance is the mass balance of water fed to power units, with all possible combinations of multiple reservoirs and without the construction of reservoirs. The purpose of such water balance is to demonstrate the requirement of specific combination of multiple reservoirs constructed under CDM project activity for the optimization of power output. This demonstration has to be carried out in the specific scenario of water availability in different seasons to optimize the water flow at the inlet of power units. Therefore, this water balance will take into account seasonal flows from river, tributaries (if any), and rainfall for minimum three years prior to implementation of CDM project activity.

for grid power plants only or, as an option, can include off-grid power plants. In the latter case, there are specific conditions that should be met. Since the electricity system affected by the proposed project activity includes only grid-connected power plants, no specific conditions should be assessed. The tool is not applicable if the project electricity system is located partially or totally in an Annex-I country.

- Tool for the demonstration and assessment of additionality (Version 06.0.0 EB 65)

  The additionally tool for the demonstration and assessment of additionality is used as stated in ACM0002 (Version 13.0.0).

B.3. Project boundary, sources and greenhouse gases (GHGs)

>>

In accordance to the description in the approved methodology ACM0002 (Version 13.0.0) "Consolidated methodology for grid-connected electricity generation from renewable sources" The spatial extent of the project boundary includes the physical power plant and all power plants connected physically to the electricity system that the CDM project power plant is connected to. Hence, the project boundary is the area of the concession where the Project and transmission lines are located up until the point of common coupling to the SEIN. Given that the transmission line will connect the Project with the SEIN, it will also be included in the Project's boundary.

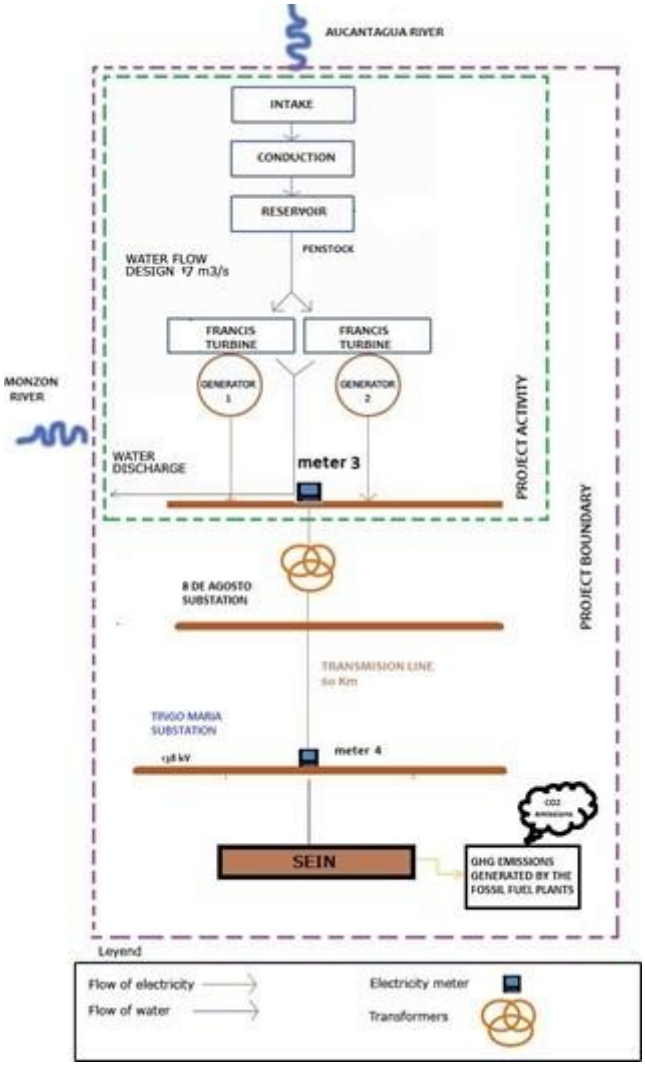
The boundary of the Project includes the sources and gases contained in the table below:

Table 3: Sources and Gases Included in the Project Boundary

Source		GHG	Included?	Justification/Explanation
Baseline	CO2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity	CO_2	Yes	Main emission source.
		CH_4	No	Minor emission source.
		N_2O	No	Minor emission source.
Project activity	For hydro power plants, emissions of CH4 from the reservoir	CO_2	No	Minor emission source.
		CH_4	No	In the case of the Project, there is no substantial reservoir.
		N_2O	No	Minor emission source.

The flow diagram of the project boundary is illustrated below:

Figure 2:Flow diagram of the project boundary



B.4. Establishment and description of baseline scenario

>>

The project activity intends to implement of a new grid-connected renewable energies power plant. Thus the baseline scenario is the electricity delivered to the national grid by the project activity that would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation source as reflected in the combined margin (CM) calculations described in the “Tool to calculate the emission factor for an electricity system” (Version 02.2.1 EB 63).

The project is in compliance with all applicable legal and regulatory requirements, including Peru's Electric Concession Law of 1992 -Law 25844 (ECL)[7]. Several articles of the ECL imply that the Project is a valid and realistic option, including:

a) Article 1: Electricity generating activities can be developed by people or legal entities, whether they are nationals or foreigners. Legal entities, i.e. private companies, should be incorporated under Peruvian laws;
b) Article 3: A concession is required for the development of hydropower plants if their installed capacity is greater than 500 kW;
c) Article 6: The concessions and authorizations can be granted by Peru's Department of Energy and Mines (MINEM);
d) Article 9: The Peruvian government seeks to preserve the environmental quality and cultural heritage of the country, as well as the rational use of natural resources in the development of activities related to generation, transmission and distribution of electricity.

In accordance with the "Tool to calculate the emission factor for an electricity system" (Version 02.2.1), the baseline emission factor is calculated using the combined margin ($\mathbf{EF_{grid,CM,y}}$) method, which consists of the weighted average of the operating margin emission factor ($\mathbf{EF_{grid,OM,y}}$) and the build margin emission factor ($\mathbf{EF_{grid,BM,y}}$). All margins are expressed in tCO_2/MWh.

$$\mathbf{EF_{grid,CM,y} = EF_{grid,OM,y} * W_{OM} + EF_{grid,BM,y} * W_{BM}}$$

According to the tool, $\mathbf{EF_{grid,CM,y}}$ can be used to calculate GHG emissions expressed in tCO_2/MWh that would have been generated in the absence of the Project. GHG emission reductions will be claimed based on the total CO_2 emissions mitigated by the Project. The Project's boundary considered is the SEIN electricity system. No leakages or indirect emissions were identified in the case of the Project.
The Project will generate electricity without emitting GHGs. It will reduce anthropogenic GHG emissions by displacing GHGs that would have been emitted if fossil fuels were burned to generate power. The Project is estimated to reduce 105,133 tCO2e annually[8], with expected total reductions of 735,931 tCO2e for the first 7 years of crediting period.

The installed capacity of the SEIN was 6,463.39 MW in 2010, of which 47.93% was hydroelectric power generation and 52.07% thermal[9]. In 2010, the total national power generation was 32,426.83 GWh, of which 58.48% was hydroelectric power and 41.52% thermal.[10]

[7] Modification made by the Law 1002 is included in the Peru's Electric Concession Law of 1992 -Law 25844 (ECL).

[8] ER estimates are based on the "Consolidated Baseline Methodology for grid-connected electricity generation from renewable sources" (ACM0002)

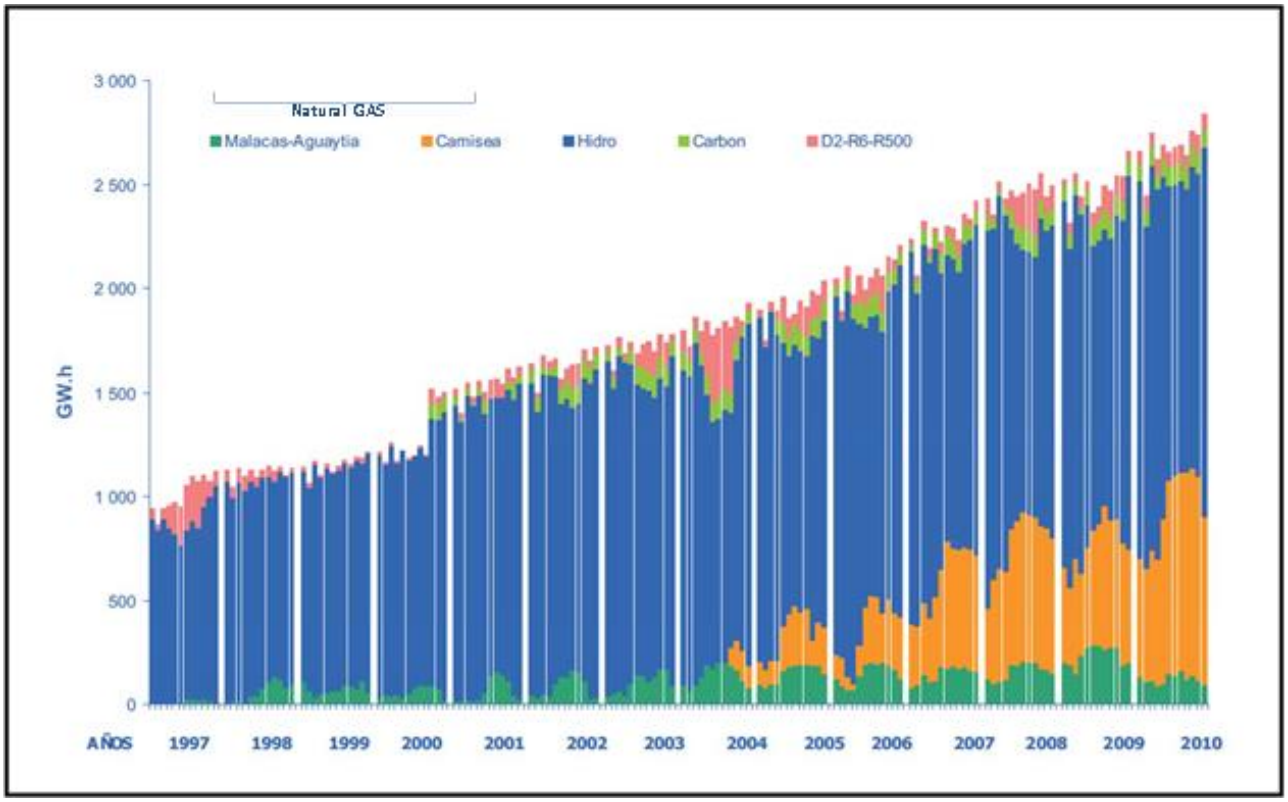
[9] See COES (2010): Annual Statistic2010, Chart 2.2

[10] See COES (2010): Annual Statistic2010, Chart 2.2

Until 1992, all developments, implementation and operation of the Peruvian power sector were exclusively under the control and authority of the government. Following the issuance of the Law of Electric Concessions in 1992, state-owned enterprises were privatized and investments in new power generation plants and transmission systems became the domain of private companies. The Law sets forth the norms of operation of the interconnected electric systems, for which an autonomous entity named Committee of Economic Operation of the Electric System (COES) was created. COES is made up of the shareholders of generation companies, the main transmission system, the distribution companies and the consumers. COES is responsible for the coordination of the SEIN system operation at minimum cost, guaranteeing the security of the electric power supply and the best use of energy resources.

Although the traditional energy source in Peru has been hydropower, the recent and on-going exploitation of the natural gas deposits of Camisea has started a new chapter in the Peruvian energy sector. Natural gas is expected to become the most important economic resource for power generation over the coming decades.

Figure 3: Evolution of the energy generation of the SEIN per source



See COES (2010): Annual Statistic 2010, figure Number 2.6. A.

In the absence of the Project, GHG emissions are not likely to be reduced due to prohibitive barriers faced by hydropower plant developers in Peru, and the existence of other conventional alternatives for power generation that are financially more attractive.

B.5. Demonstration of additionality

>>

Since the earliest stages of planning the Project, the Project developer has considered the need for CDM assistance. According to the "Guidelines on the Demonstration and Assessment of Prior Consideration of the CDM", Version 04 (EB 62 15/07/2011), new project activities starting after 02/08/2008 must notify the Designated National Authority (DNA) and the UNFCCC in writing of the commencement of the project activity. The Project was announced to the UNFCCC secretariat on 24/08/2011 and it was sent to the Peruvian DNA.

The real and continued actions taken to secure CDM status of the project can be demonstrated by the elements presented in the Table below.

Table 4: Timeline for the development of the proposed Project

Date	Key Event	Comment
01/07/2011	Pre feasibility study	
08/07/2011	Signing of the Shareholders' Agreement between Andes and EnBW.	In the Shareholders' Agreement the purpose to develop and implement the Project as a CDM project activity is clearly stated. Further EnBW is agreed on becoming the offtaker of the CERs generated by the Project.
02/08/2011	Purchase Order for developing the CDM documentation of the Project	Contract signed for the PDD consultant
24/08/2011	Prior Consideration of the CDM	The Project was announced to the UNFCCC secretariat and it was sent to the Peruvian DNA.
11/09/2011	Local Stakeholder Conference	Local Stakeholder Conference (LSC) took place. The LSC has been organized by FONAM.
30/09/2011	Signature of the PPA with the Peruvian government.	A power purchase agreement (PPA) was signed with the government in the course of the RER auction. The signature of the PPA requires a performance bond to be issued of a substantial amount and requires the project sponsors to commission the Project until 31/12/2014. Therefore this date constitutes the investment start date.

28/02/2013	Estimated project start date	In accordance with the working chronogram of the project developers at this date financial closing of the project shall be reached, which constitute the date on which the project participants will commit to expenditures related to the implementation or related to the construction of the project activity. This shall be the estimated project start date.

The following steps from the "Tools for the demonstration and assessment of additionality" Version 06.0.0, are carried out in this section:

Step 1: Identification of alternatives to the project activity consistent with mandatory laws and regulations
Step 2: Investment analysis
Step 3: Barriers analysis
Step 4: Common practice analysis

Step 1 - Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a. Define alternatives to the project activity:

Three realistic and credible alternatives were identified as available to the Project participants, which provide outputs or services comparable with the proposed CDM project activity. These are:

1. Implement the Project as hydroelectric power generation, but without CDM assistance;
2. Implement the Project as a fossil fuel-fired thermal plant; or,
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, including Peru's Electric Concession Law of 1992 -Law 25844 (ECL).2[11] None of the identified alternatives contradicts any legal or regulatory requirement, or poses a risk to do so in the future. Moreover, none of them breaches technical standards and dispositions of environmental and cultural conservation.

[11] Modifications made by the Law 1002 are included in the Peru's Electric Concession Law of 1992 -Law 25844 (ECL).

STEP 2 – Investment Analysis[12]

Sub-step 2a – Determine appropriate analysis method

The CDM project activity generates financial and economic benefits other than CDM related income, thus the simple cost analysis does not apply. In order to determine whether the proposed Project is economically or financially less attractive than the other alternatives without the revenue from the sale of CERs, Option III – "Apply benchmark analysis", is performed below.

Sub-step 2b – Option III – Apply benchmark analysis

The indicator that will be used is Project IRR. Project IRR is a suitable financial indicator for the Project and is compared to a calculated benchmark, which is the discount rate that represents the returns investors or borrowers would normally expect in Peru.

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

Project IRR Calculation: The table below presents the main data used in the IRR calculation of the Project. The calculation was based on conservative assumptions without financing, because access to finance was not granted for the project, the investment decision was taken without considering financing,

Assumptions, are listed below in order to maintain a transparent approach.

Table 5: Financial data used for the Project's IRR calculation

Parameter	Unit	Value	Data Source
Generation capacity	MW	20.576	name plate capacity of both generators according to equipment purchase contract
Net electricity generation and delivery to the SEIN per year	MWh	159,442	calculation in accordance with the methodology and the business case
Energy committed with PPA	in MWh per year	140,000	Power Purchase Agreement signed on 30/09/2011
PPA price	USD/MWh	53.90	Power Purchase Agreement signed on 30/09/2011
Electricity tariff	USD/MWh	34.302	OSINERGMIN Resolution N° 067-2011-OS/CD; Average price for off-peak and peak electricity tariff
Capacity tariff	US/MW/month	6,028.5	OSINERGMIN Resolution N° 067-2011-OS/CD

[12] The investment analysis takes into consideration the following guideline: "Guidelines on the assessment of investment analysis" (Version 05). See in the internet: http://cdm.unfccc.int/Reference/Guidclarif/reg/reg_guid03.pdf; web site accessed on 169/01/2012.

Load factor[13]	%	90.00	Pre Feasibility study (2011). The study is considering a hydrological study using data from more than 30 years from measurements at the Monzon river.
Transmission losses	%	1.67	Project developer internal calculation and verified by an external consultant.
Initial investment: Machinery & Equipment	in USD	7,129,490.58	CAPEX GENERACION ANDINA S.A.C. FINANCIAL STATEMENTS DECEMBER 31, 2019 AND DECEMBER 31, 2018, page 29[14]
Initial investment: Civil Works	in USD	30,691,625.78	CAPEX GENERACION ANDINA S.A.C. FINANCIAL STATEMENTS DECEMBER 31, 2019 AND DECEMBER 31, 2018 page 29[15]
Initial investment: Grid integration	in USD	6,747,297.29	CAPEX GENERACION ANDINA S.A.C. FINANCIAL STATEMENTS DECEMBER 31, 2019 AND DECEMBER 31, 2018 page 29[16]
Mobil machinery	in USD	1,121,534.58	Adding up to total investment as stated in GENERACION ANDINA S.A.C. FINANCIAL STATEMENTS DECEMBER 31, 2019 AND DECEMBER 31, 2018 page 29[17]
Technical lifetime of the Project	years	30	Pre Feasibility study (2011): [18]
Operation and Maintenance	in TUSD per year	450	Project developer internal calculation in accordance with similar projects in Perú
Administration	in TUSD per year	300	Project developer internal calculation in accordance with similar projects in Perú
Insurance costs	% of CAPEX per year	1.00	Pre Feasibility study (2011)

[13] The load factor calculation is in line with the following guideline: “Guidelines for the reporting and validation of plant load factors” (Version 01).

[14] Detailed CAPEX per position presented in spreadsheet Generacion Andina Assets v2019.12.31

[15] Detailed CAPEX per position presented in spreadsheet Generacion Andina Assets v2019.12.31

[16] Detailed CAPEX per position presented in spreadsheet Generacion Andina Assets v2019.12.31

[17] Detailed CAPEX per position presented in spreadsheet Generacion Andina Assets v2019.12.31

[18] Project lifetime of 30 years is considered to be conservative, taking into account that the analysis period for IRR calculation used by the Peruvian Electric Tariff Commission is 25 years without residual value. See ECL, Law Decree 25884, Article 70 in the internet: http://www2.osinerg.gob.pe/MarcoLegal/pdf/LEYCE-DL25844.pdf; web link accessed on 09/11/2011.

Overhauling costs every 5 years	in TUSD	100	Project developer internal calculation in accordance with similar projects in Perú
Social Investment Plan	in TUSD	9.728	FONAM (2011): Local Stakeholder Consultation report
Discount rate	%	12.00	Law 25844 – Electronic Concessions Law, Article 79, p.40[19]
CER price	EUR	4.9	Price calculated in accordance with the Emission Reduction Purchase Agreement Clause as set forth in the Shareholders' Agreement considering the spot market price as per 30/09/2011 derived from Bluenext:[20]
Emission Factor	tCO2e/MWh	0.65938	Calculated in accordance with the procedures set forth in this document
Water Tariff	% of the electricity tariff per year	1.00	Law 25844 – Rulebook for the Electric Concessions Law. Article 214, p. 92[21]
Contribution to OSINERGMIN	% of revenues per year	1.00	Executive order No. 136-2002-PCM from 24/12/2002[22]
Contribution to COES	% of revenues per year	0.75	COES (Committee of Economic Operation of the System) Administrative Procedure 8A[23]
Exchange Rate	S/. per USD	2.805	OSINERGMIN Resolution N° 067-2011-OS/CD
Exchange Rate	USD per EUR	1.35968	Exchange rate as per 30/09/2011 as provided by www.oanda.com; web link accessed on 08/11/2011.
Income Tax	% per year	30.00	Income Tax Law, chapter VII, Article 55[24]

[19] See in the internet: http://www2.osinerg.gob.pe/MarcoLegal/pdf/LEYCE-DL25844.pdf; web link accessed on 09/11/2011.

[20] See in the internet: http://www.bluenext.eu/statistics/downloads.php; web link accessed on 09/11/2011.

[21] See in the internet: http://www2.osinerg.gob.pe/MarcoLegal/pdf/REGLACE.pdf; web link accessed on 09/11/2011.

[22] See in the internet: http://www.osinerg.gob.pe/newweb/uploads/JARU/CD/008fiscalizacion/ds136-2002-pcm.pdf; web link accessed on 09/11/2011

[23]. See in the internet: http://www.coes.org.pe/dataweb2/2008/DO/PROCEDIMIENTOS/Proced_admin_8a.pdf; web link accessed on 09/11/2011

[24] See in the internet: http://www.sunat.gob.pe/legislacion/renta/ley/capvii.htm; web link accessed on 09/11/2011

Depreciation – Civil Works	% per year	3.00	Rulebook of the Income Tax Law, Chapter VI, Article 22[25]
Depreciation – Machinery & Equipment	% per year	10.00	Rulebook of the Income Tax Law, Chapter VI, Article 22[26]
Distribution of income to workers	% per year	5.00	Law 892, Article 2[27]

Discount Rate: The after tax discount rate of 12.00% has been selected as a benchmark to evaluate the economic viability of an investment in the power sector in Peru. This 12.00% discount rate emerged in several studies, as well as in official governmental decisions related to project investment evaluation.
The 12.00% rate appeared officially for the first time in December 1992 with the issuance of the ECL as the opportunity cost of investment for new additions to the national grid of Peru in order to forecast and determine the regulated tariff in Peru.[28] In addition, there are several other governmental regulations not related to tariffs that use 12.00% as the rate of the opportunity cost for the evaluation of new investments, reflecting the minimum expected return for investments in Peru's power sector. In 2007 the Ministry of Economy and Finance issued the Decree 015-2007: *Terms of reference for feasibility studies for rural electrification in Peru*.[29] In section number 5.2, the Decree stipulates that for private sector investment evaluation a 12.00% discount rate should be used for rural electrification projects, which include both renewable and non-renewable generation. Prior to this, in May 2005, the Ministry of Economy and Finance had issued the *Technical report 085-2005-EF/68.1* regarding the evaluation of projects in the electric sector. This report establishes that the discount rate is 12.00% for private sector project evaluation.[30]

Comparison of Project IRR to benchmark: The Project's IRR is compared to the benchmark to examine the financial attractiveness of the Project. The Project's IRR is calculated with 8.80%;

[25] See in the internet: http://www.sunat.gob.pe/legislacion/renta/regla/index.html; web link accessed on 09/11/2011.

[26] See in the internet: http://www.sunat.gob.pe/legislacion/renta/regla/index.html; web link accessed on 09/11/2011.

[27] See in the internet: http://www.mintra.gob.pe/contenidos/archivos/prodlab/D.%20Leg.%20892%2011-11-96.pdf; web link accessed on 09/11/2011.

[28] See Law Decree N° 25844: Electricity concessions Law; Article 79. Regarding the issue of tariff applicability, Peru does not have a special tariff for non-renewable or renewable power projects. The 12% discount rate for the electric sector applies to both renewable and non renewable projects and is considered post tax.

[29] See in the internet: http://www.mef.gob.pe/DGPM/docs/legal/normasv/snip/RD_008_anex.pdf; web link accessed on 09/11/2011.

[30] See in the internet: http://www.mef.gob.pe/DGPM/docs/infor/ener/12078.pdf; web link accessed on 09/11/2011.

which is below the defined benchmark of 12.00%. Thus, this Project is not financially attractive without considering additional revenues from the sales of carbon credits. Considering said additional income streams the IRR of the total investment would increase to 9.81%. Therefore, the financial evaluation demonstrates the crucial contribution of CER revenues for making the project more financially viable.

Table 6: Comparison of financial indicator with and without CER revenues

	Project IRR w/o CER revenue	Project IRR with CER revenue
IRR in %	8.80	9.81

Sub-step 2d –Sensitivity Analysis

The following assumptions are established to examine whether the above conclusions regarding the financial attractiveness of the Project are robust:
Project IRR: A sensitivity analysis has been applied to the IRR to explore at what value of each key parameters, the IRR would reach the benchmark. Following three key parameters have been chosen: (1) Initial investment costs, (2) load factor and, (3) electricity tariff. The results are summarized in the following table.

Table 7: Sensitivity Analysis: IRR turning point condition to exceed the 12% benchmark		
-23.9%	+ 138.0%	+41.6%
Initial investment costs	Electricity tariff[31]	Load factor

The probability of such variations in any of these parameters shown in the table above is considered improbable as reasoned below:

- The initial investment costs are not likely to decrease by 23.9%. The budgeted costs are with respect to the electromechanical equipment and parts of the civil works backed by quotes of suppliers. These costs were based on actual investment costs as derived from an audited financial statement[32] However, currently costs for civil works for hydropower projects tend to escalate significantly higher than the general rate of inflation in Peru.[33]

[31] The sensitivity only applies to the energy tariff for the electricity not committed by the PPA, which has a tenor of 20 years.

[32] GENERACION ANDINA S.A.C. FINANCIAL STATEMENTS DECEMBER 31, 2019 AND DECEMBER 31, 2018

[33] ESMAP (2011), Peru Opportunities and Challenges for Small Hydropower Development, p. 21.

- The tariff for 140,000 MWh annually generated is fixed in the course of the PPA signed with the Peruvian government over the course of the upcoming 20 years after commissioning of the Project. The prevailing spot market tariff in Peru is low and is not likely to increase by 138%. The spot price is established by the regulator OSINERGMIN, who calculates it based on the cost of the fuel used in the total electricity generation, which is mainly natural gas and diesel. Natural gas has a very low price due to domestic availability and legislative promotion of said prices.[34]

- It is not likely that the load factor increases by a value of 41.6%. The calculation of the load factor is based on hydrological data available over more than 30 years. Furthermore, back up on-site measurements currently performed at the Project site indicate that the available water flow might be less than previously projected by the model.

In conclusion, the sensitivity analysis conducted above confirms that the Project is not financially attractive for private investors and its successful implementation requires the assistance of the CDM revenues. As a result, the Project is considered additional under Step 2.

Step 3. Barrier Analysis

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

a) Investment Barriers:

The Project is a small scale greenfield hydro power project owned originally by a small Peruvian company. The original project developer, Andes, is not affiliated with a large company or legal entity; it is comprised of individuals as its shareholders. Small projects such as this one have limited access to capital markets.[35] Moreover, commercial investors tend to prefer low-risk, noncapital-intensive projects with short construction periods and rapid returns on investment. Thermal generation projects have these characteristics[36] and have been the common practice in Peru.
Following a close dialogue EnBW agreed in 2011 to provide an equity investment in the Project to finance the Project's development pro rata to its stakeholding interest in the project company. Such

[34] ESMAP (2011), Peru Opportunities and Challenges for Small Hydropower Development, p. 49 notes [h.i.o]: "The low price of natural gas and the resulting low tariff for power generation (which is even declining in real terms) have made it very difficult for most small hydro projects to compete in the marketplace." The study further states at p.19: "The current Peruvian price of gas for power generation is below the opportunity cost, as set by the international market for traded LNG." The study defines small hydro projects as projects with an installed capacity below 20 MW.

[35] ESMAP (2011): Peru Opportunities and Challenges of Small Hydropower Development, p. 32, World Bank Group; in the internet: http://www.esmap.org/esmap/sites/esmap.org/files/7747-ESMAP%20Peru%20English%20Web_4-11-11_0.pdf; web link accessed on 09/11/2011.

[36] ESMAP (2011): Peru Opportunities and Challenges of Small Hydropower Development, p. 1, World Bank Group; in the internet: http://www.esmap.org/esmap/sites/esmap.org/files/7747-ESMAP%20Peru%20English%20Web_4-11-11_0.pdf; web link accessed on 09/11/2011.

investment was predicated on and motivated by gaining access to the carbon credits from the Project in order to meet EnBW's compliance commitments under the EU-ETS. The carbon credits both provided an incentive to become involved in the project when many risks were not elaborated, and will provide a very important boost to the Project's revenues. The shareholders's agreement states that the Project has to be developed as a CDM project, and it reflects the fact that EnBW's sole motivation for investing was the acquisition of the carbon credits that could be generated by the Project, as the agreement includes an Emission Reduction Purchase Agreement clause whereas EnBW is granted the right to acquire the generated CERs, and the agreement also includes a put option for EnBW to sell its shares if the Project is not registered under the CDM.[37] Furthermore, EnBW's investment in a hydro power project in Peru is solely for the purpose of securing carbon credits for its own compliance commitments under the EU-ETS, as according to the present strategy of EnBW, Peru is not a target country for investments.[38]

Thus, investment barrier in the case of this Project has been mitigated through the availability of carbon credits, which provide capital access as a result of the investor's motivation to invest for a return linked to carbon credits

Sub-step 3b. Show that the identified barriers would not prevent the implementation of at least one of the alternatives (except the proposed project activity):

The identified barrier that the Project faces will not prevent the non-project alternatives: "Implement the Project as a fossil fuel-fired thermal plant (alternative 2) and "Do not implement any power generation project" (alternative 3).

Having identified a barrier that prevent the implementation of this type of proposed project activity (hydropower plants) but did not prevent at least one of the alternatives identified, it can be concluded that the Project is additional under Step 3

Step 4. Common Practice Analysis

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

This step analyze if there are other activities that are operational and that are similar to the proposed project activity. Projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc.

Other CDM project activities (registered project activities and project activities which have been published on the UNFCCC website for global stakeholder consultation as part of the validation process) are not to be included in this analysis.

[37] See Shareholders Agreement (2011) between Andes and EnBW.

[38] See EnBW Annual Report (2010), p.105: "EnBW is focusing on selected countries in central and eastern Europe as well as Turkey." See also p. 25 and p. 124.

The tool to Demonstration and assessment of additionality (version 06.0.0) propose four steps to determine if the proposed project activity is a common practice.

Step 1: Calculate applicable output range as +/-50.00% of the design output or capacity of the proposed project activity.

The applicable geographical area is Peru.

Table 8:Output range of the design capacity: 9.5 MW – 28.5 MW

	GENERATING PLANTS[39]	CAPACITY (MW) [40]
1	Carhuaquero IV	10.00
2	Chiclayo Oeste	26.67
3	Chilina Combined Cycle	21.00
4	Chilina Sulzer (1 and 2)	10.46
5	Chilina TV2/TV3	17.00
6	Chimbote	20.96
7	Huanchor	18.36
8	Independencia	22.93
9	La Joya	10.00
10	Paramonga	23.00
11	Piura	13.66
12	Piura TG	23.25
13	Poechos II	10.00
14	Tumbes	18.68
15	Yarinacocha	25.36

Step 2: In the applicable geographical area, identify all plants that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all}. Registered CDM project activities shall not be included in this step.

Table 9: Step 2 demonstration

	GENERATING PLANTS[41]	CDM
1	Carhuaquero IV	Yes

[39] See COES (2010): COES Annual Statistic 2010, Chart 15.5.

[40] See COES (2010): COES Annual Statistic 2010, Chart 15.5.

[41] See COES (2010): COES Annual Statistic 2010, Chart 15.5.

2	Chiclayo Oeste	No
3	Chilina Combined Cycle	No
4	Chilina Sulzer (1 and 2)	No
5	Chilina TV2/TV3	No
6	Chimbote	No
7	Huanchor	No
8	Independencia	No
9	La Joya	Yes
10	Paramonga	No
11	Piura	No
12	Piura TG	No
13	Poechos II	Yes
14	Tumbes	No
15	Yarinacocha	No

$N_{all} = 12$

Step 3: Within the plants identified in Step 2, identify those that apply technologies different than the technology applied in the proposed project activity. Note their number N_{diff}.

Table 10: Step 3 demonstration

	GENERATING PLANTS[42]	CAPACITY (MW)[43]	SIZE OF INSTALLATION	TECHNOLOGY[44]	ENERGY SOURCE/FUEL	DIFFERENT INVESTMENT CLIMATE	OBSERVATION
1	Chiclayo Oeste	26.67	Large	Diesel	Diesel	Yes	Different Fuel
2	Chilina Combined Cycle	21.00	Large	CCOMB	Natural Gas	Yes	Different Fuel
3	Chilina Sulzer (1 and 2)	10.46	Small	Diesel	Diesel	Yes	Different Fuel
4	Chilina TV2/TV3	17.00	Large	TV	Natural Gas	Yes	Different Fuel

[42] See COES (2010): COES Annual Statistic 2010, Chart 15.5.

[43] See COES (2010): COES Annual Statistic 2010, Chart 15.5.

[44] See COES (2010): COES Annual Statistic 2010, Chart 15.5.

5	Chimbote	20.96	Large	TG	Natural Gas	Yes	Different Fuel
6	Huanchor	18.36	Large	Francis	Hydro	Yes	Different Investment Climate
7	Independencia	22.93	Large	TG	Natural Gas	No	Different Fuel
8	Paramonga	23.00	Large	TG	Natural Gas	No	Different Fuel
9	Piura	13.66	Small	Diesel	Diesel	Yes	Different Fuel
10	Piura TG	23.25	Large	Diesel	Diesel	Yes	Different Fuel
11	Tumbe	18.68	Large	Diesel	Diesel	Yes	Different Fuel
12	Yarinacocha	25.36	Large	Diesel	Diesel	Yes	Different Fuel

N_{diff}= 12

Investment climate at the date of the investment decision

Although the traditional energy source in Peru has been hydropower, the recent and on-going exploitation of the natural gas deposits of Camisea has started a new chapter in the Peruvian energy sector. Natural gas has become the most important economic resource for power generation over these years. In February 2000, the government issued the licenses to exploit natural gas from the Camisea gas field and a concession for natural gas and liquefied natural gas (LNG) transportation in October 2000. By the commissioning of the Camisea project in August 2004, the government issued the following laws in order to promote natural gas-fired electricity generation and to exempt the selective consumption tax to natural gas: (1) DS 019-2004 on 25/06/2004; (2) DS 041-2004-EM on 24/11/2004; and (3) DS 107-2004-EF on 05/08/2004. Those laws aimed at making natural gas an even more competitive alternative for power generation than hydropower. Additionally in December 2005, the government issued the decree on cogeneration, DS N° 064-2005-EM, encouraging simultaneous generation of heat and electricity using natural gas in order to encourage the use of natural gas in all activities including electricity generation. The impacts of these government efforts to promote natural gas development, distribution, electricity generation, and co-generation compound the challenges faced by hydropower developers, who must compete not only with a cheaper generation technology, that is, combined cycle plants, but also with a much cheaper fuel, natural gas, which is increasingly available locally.

The following table shows the power plants that have been added to the SEIN since 2004, the year in which the Camisea natural gas project was commissioned:

Table 11: Additions to the SEIN from 2004 to 2010[45]

Enterprise	Power plant	Unit	Technology	Installed Capacity (MW)	Date of Commissioning	Comments
EDEGEL	Santa Rosa Westinghouse	TG7	Natural Gas turbine	127.50	01/06/2005	Natural Gas from Camisea
EDEGEL	Santa Rosa UTI 5 & 6	UTI UTI 5, 6	Natural Gas turbine	119.20	01/06/2006 - 01/08/2006	Natural Gas from Camisea
ENERSUR	Chilca 1TG1	TG1	Natural Gas turbine	175.96	01/12/2006	Natural Gas from Camisea
KALLPA GENERACION	Kallpa TG1	TG1	Natural Gas turbine	180.00	24/07/2007	Natural Gas from Camisea
ENERSUR	Chilca 1TG2	TG2	Natural Gas turbine	174.53	07/08/2007	Natural Gas from Camisea
SDF ENERGIA	Oquendo		Natural Gas turbine	31.00	19/01/2009	Natural Gas from Camisea
KALLPA GENERACION	Kallpa TG2	TG2	Natural Gas turbine	216.00	19/06/2009	Natural Gas from Camisea
ELECTROPERU	Trujillo Norte		Diesel 2 64.00	28/06/2009	Diesel	
ENERSUR	Chilca 1TG3	TG3	Natural Gas turbine	199.80	22/07/2009	Natural Gas from Camisea
EDEGEL	Santa Rosa TG8	TG8	Natural Gas turbine	193.18	01/08/2009	Natural Gas from Camisea

[45] According to the CDM rules in the context of conducting common practice analysis, project participants may exclude registered CDM project activities. Hence Ventanilla (combined cycle), Huaycoloro LFG to Energy project and the hydropower plant projects of Callahuanca, Carhuaquero IV, Caña Brava, Santa Cruz I , Santa Cruz II, La Joya, Platanal, Poechos II and Pias 1 have been excluded from the table because of their CDM status (registered).

AGRO INDUSTRIAL PARAMONGA	Paramonga		Gas turbine/ Cogeneration/Bio mass	23.00	01/12/2009	Cogeneration Bagase/Diesel	
KALLPA GENERACION	Kallpa TG3	TG3	Natural turbine	Gas	233.00	01/02/2010	Natural Gas from Camisea
DUKE ENERGY	Las Flores	TG1	Natural turbine	Gas	192.5	01/04/2010	Natural Gas from Camisea
MAJA ENERGIA	Roncador	U1 & U2	Hydro	3.80	01/04/2010	Hydro	
EGASA	Pisco	TG1 TG2	Natural turbine	Gas	74.80	01/08/2010	Natural Gas from Camisea
EGESUR	Independencia		Natural turbine	Gas	22.93	01/09/2010	Natural Gas from Camisea

Source: COES (2010): Annual Statistic 2010, p. 87-88

Therefore, projects developed after 2004 face a different investment climate due to the cheap availability of natural gas[46] and promotion policies of the government, that have made the use of this fuel in generating electricity more feasible, generating significant investments in the installation of new power thermal plants since then.

Step 4: Calculate factor $F=1-N_{diff}/N_{all}$ representing the share of plants using technologies similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.

$F = 1 - (N_{diff}/N_{all})$	**$N_{all} - N_{diff}$**
0	0

The proposed project activity is common practice within a sector in the applicable geographical area if the factor F is greater than 0.2 and $N_{all}-N_{diff}$ is greater than 3. In this case the factor is 0. Therefore, the project is not common practice.

[46] ESMAP (2008): Peru Institutional and Financial Framework for Development of Small Hydropower, p. 67 notes: "The low price of natural gas and the resulting low tariff for power generation (which is even declining in real terms) has made it very difficult for most small hydro projects to compete in the market place." This statement has been repeated in ESMAP (2011): Peru Opportunities and Challenges for Small Hydropower Development, p. xiii and xiv.

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

The following table provided by the electric sector regulator (OSINERGMIN)[47] shows the power plants that were under construction at date.

Table 12:: Power plants under construction[48]

Company	Power Plant	Type	Installed capacity (MW)	Expected Date of Commissioning
EGESUR	Re Location C.T Calana – Natural Gas	Turbo Gas-Natural Gas	229.00	10/ 2010
EGASA	Re Location TG – CT Mollendo	Turbo Gas-Natural Gas	73.20	09/2010
SHOUGESA	CT El Faro	Diesel	171.70	09/2011
TERMOCHILCA	CT Santo Domingo de los Olleros	Turbo Gas-Natural Gas	197.60	06/2012
SHOUGAN	CT San Nicolas II	Diesel 2	169.00	09/2011
EGEMSA	H P Machupicchu II	Hydro	101.75	02/ 2012
CONSORCIO ENERGORET INGENIEROS CONSULTORES EIRL	HP Shima	Hydro	5.00	10/2012
KALLPA	CC Kallpa	Combined Cycle Natural Gas	858.60	09/2012
FENIX POWER	CT Fenix	Turbo Gas-Natural Gas	521.50	09/2012
CONSORCIO COBRA PERU S.A.	Marcona	Wind	32.00	12/2012
ENERGIA EOLICA S.A.	Talara y Cupesnique	Wind	110.00	07/2012

Source: OSINERGMIN (2010): Estudio Técnico Económico de determinación de Precios de Potencia y Energía en Barras para la Fijación Tarifaria de Mayo de 2010, in the internet: http://www2.osinerg.gob.pe/gart.htm; web link accessed 11/11/2011.

[47] See Osinergmin (2010): SCG-Estudio Técnico Económico de Determinación de Precios de Potencia y Energía en barras para la Fijacion Tarifaria de Mayo de 2011, p. 16f.

[48] According to the CDM rules and the recent clarification of the 38 meeting of The Executive Board paragraph 60, in the context of conducting common practice analysis, project participants may exclude registered CDM project activities and project activities which have been published on the UNFCCC CDM website for global stakeholder consultation as part of the validation process. So the hydropower plant projects of Nuevo Imperial, Purmacana, Huashuasi I y II and Yanapampa have been excluded from the table because of their CDM status (registered or under validation). Also the projects of Huaycoloro Biomass Energy Project and the solar energy projects of Panamericana- Majes have been excluded for the same reason.

As Table 12 above illustrates, only 4.30% of the installed capacity under construction will be from hydroelectric power, whereas the remaining 95.7% is shared between natural gas-fired thermal generation (90.00%) and wind farms (5.70%). The only two hydropower projects in the table are Machupicchu II and Shima. Machupicchu is a rehabilitation project of an existing hydro project and it is a public investment; therefore, is not comparable to the proposed project activity. Shima is the only green field small scale hydropower project and is private. As it represent only 0.20% of the new additions under construction, it is correct to confirm that hydro projects are not the common practice in Peru.

Based on these circumstances, the Project is not common practice, but rather, an exception that would likely not have materialized without CDM revenues. Thus, the Project is additional.

B.6. Estimation of emission reductions

B.6.1. Explanation of methodological choices

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The emission reduction (ER_y) for the Project:

According to methodology ACM0002 (Version 13.0.0), the emission reduction *ER y by* the project activity during a given year *y* is calculated as follows:

$ERy = BEy – PEy$

Where:

ER_y = Emission reductions in year *y* (t CO_2e/yr)
BE_y = Baseline emissions in year *y* (t CO_2/yr)
PE_y = Project emissions in year *y* (t CO_2e/yr)

Project Emissions (PEy)

According to ACM0002 (Version 13.0.0),

$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y}$

Where:

PE_y = Project emissions in year *y* (tCO_{2e}/yr)
$PE_{FF,y}$ = Project emissions from fossil fuel consumption in year *y* (tCO_2/yr)
$PE_{GP,y}$ = Project emissions from the operation of geothermal power plants due to the release of non-condensable gases in year *y* (tCO_{2e}/yr)
$PE_{HP,y}$ = Project emissions from water reservoirs of hydro power plants in year *y* (tCO_{2e}/yr)

For the hydropower project activity, the value of $PE_{FF,y}$ and $PE_{GP,y}$ are zero.

Emissions from water reservoirs of hydro power plants ($PE_{HP,y}$)

For hydro power project activities that result in new single or multiple reservoir and hydro power project activities that result in the increase of single or multiple existing reservoir, project proponents shall account for CH_4 and CO_2 emissions from the reservoirs, estimated as follows:

a) If the power density of the single or multiple reservoirs (PD) is greater than 4 W/m^2 and less than or equal to 10 W/m^2:

$$PE_{PH,y} = \frac{EF_{Res} \cdot TEG_y}{1000}$$

Where:

$PE_{HP,y}$	= Project emissions from water reservoirs (tCO_2e/yr)
EF_{Res}	= Default emission factor for emissions from reservoirs of hydro power plants in year *y* ($kgCO_2e/MWh$)
TEG_y	= Total electricity produced by the project activity, including the electricity supplied to the grid and the electricity supplied to internal loads in year *y* (MWh)

b) If the power density of the project activity (PD) is greater than 10 W/m^2:

$$PE_{HP,y} = 0$$

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

$$PD = \frac{Cap_{PJ} - Cap_{BL}}{A_{PJ} - A_{BL}}$$

Where:

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

A_{BL} = Area of the single or multiple reservoirs measured in the surface of the water, before the implementation of the project activity, when the reservoir is full (m^2). For new reservoirs, this value is zero

Baseline emissions (BE_y)

Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity. The methodology assumes that all project electricity generation above baseline levels would have been generated by existing grid-connected power plants and the addition of new grid-connected power plants. The baseline emissions are to be calculated as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{grid,CM,y}$$

Where:

BEy = *Baseline emissions in year y (tCO2/yr)*

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr)

$EF_{grid,CM,y}$ = Combined margin CO_2 emission factor for grid connected power generation in year *y* calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (tCO_2/MWh)

Calculation of $EG_{PJ,y}$

Greenfield renewable energy power plants

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

$$EG_{PJ,y} = EG_{facility,y}$$

Where:

$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr)

$EG_{facility,y}$ = Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y* (MWh/yr)

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

Estimation of emissions reductions prior to validation

The Baseline emission factor is calculated as a combined margin ($EF_{grid,CM,y}$), following the guidance in the "Tool to calculate the emission factor for an electricity system", Version 02.2.1 According to the tool, the baseline emission factor is calculated as the weighted average of the Operating Margin emission factor ($EF_{grid,OM,y}$) and the Build Margin emission factor ($EF_{grid,BM,y}$) where the weights w_{OM} and w_{BM}, by default, are 50% (i.e., $w_{OM} = w_{BM} = 0.5$). This is presented below:

Estimated anthropogenic emissions were calculated for the Project following a 6-step-process:

Step 1: Identify the relevant electricity systems.
Step 2: Choose whether to include off-grid power plants in the project electricity system (optional) Step 3: Select a method to determine the operating margin (OM)
Step 4: Calculate the operating margin emission factor according to the selected method
Step 5: Calculate the build margin (BM) emission factor
Step 6: Calculate the combined margin (CM) emissions factor

Step 1: Identify the relevant electricity systems
The Project will supply electricity to the SEIN. The Project will be connected through a 58.67km long transmission line at a 138 kV level to the Tingo Maria substation.

Electricity imports from other grids have not been reported, neither by the COES dispatch center or MINEM. Even if there were imports, for the purpose of determining the OM emission factor, the assumed emission factor for net electricity imports is 0. Electricity exports to other grids have been reported by the COES dispatch center. Therefore, exports should not be subtracted from electricity generation data used in calculating and monitoring the electricity emission factors.

Step 2: Choose whether to include off-grid power plants in the project electricity system (optional)
Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:

Option I: Only grid power plants are included in the calculation.

Option II: Both grid power plants and off-grid power plants are included in the calculation.

Since project participants considered only grid power plants for the calculation of the operating margin and build margin emission factor, Option I is selected.

Step 3: Select a method to determine the Operating Margin (OM)
The calculation of the Operating Margin emission factor ($EF_{grid,OM,y}$) is based on one of the following methods:

a) Simple OM,
b) Simple adjusted OM,

c) Dispatch Data Analysis OM, or
d) Average OM.

Out of four options for the OM, the Dispatch Data Analysis OM (option c) was selected. The Simple OM method cannot be used since low cost, must-run resources constitute more than 50.00% of total grid generation in Peru.[49] Also, it was not necessary to use either the Simple Adjusted OM approach or the Average OM approach because detailed dispatch data is available.

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

The formula for the Dispatch Data Analysis OM emission factor ($EF_{grid,OM-DD,y}$) used was provided by the tool as follows:

$$\mathbf{EF_{grid,OM-DD,y} = \sum_h EG_{PJ,h} * EF_{EL,DD,h} / EG_{PJ,y}}$$

Where:

$EF_{grid,OM-DD,y}$	**=** Dispatch data analysis operating margin CO_2 emission factor in year *y* (tCO_2/MWh)
$EG_{PJ,h}$	**=** Electricity displaced by the project activity in hour *h* of year *y* (MWh)
$EF_{EL,DD,h}$	**=** CO_2 emission factor for grid power units in the top of the dispatch order in hour *h* in year *y* (tCO_2/MWh)
$EG_{PJ,y}$	= Total electricity displaced by the project activity in year *y* (MWh)
h	= Hours in year *y* in which the project activity is displacing grid electricity
y	= Year in which the project activity is displacing grid electricity

The $EF_{EL,n,y}$ is calculated as per the guidance for the simple OM, using the option A2.

$$\mathbf{EF_{EL,m,y} = (EF_{co2,m,i,y} * 3.6)/(\eta_{m,y}).}$$

Where:

$EF_{EL,m,y}$	= CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh)
$EF_{CO2,m,i,y}$	= Average CO2 emission factor of fuel type i used in power unit m in year y (t CO_2/GJ)
$\eta_{m,y}$	= Average net energy conversion efficiency of power unit *m* in year *y* (ratio)
m	= All power units serving the grid in year y except low-cost/must-run power units
y	= applicable year during monitoring (*ex-post* option)

[49] See: COES Annual Statistic (2010), Chart 12.2 and Chart 2.2 A.

Where several fuel types are used in the power unit, use the fuel type with the lowest CO_2 emission factor for $EF_{CO2,m,i,y}$.

Step 5: Calculate the Built Margin (BM) emission factor

In terms of vintage of data, project participants have chosen Option 1: For the first crediting period, calculate the build margin emission factor prior validation (ex ante) based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation. For the second crediting period, the build margin emission factor should be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This option does not require monitoring the emission factor during the crediting period.

According to the tool, the sample group of power units m used to calculate the build margin should be determined as per the following procedure, consistent with the data vintage selected above:

a) Identify the set of five power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently (SET5-units) and determine their annual electricity generation ($AEG_{SET\text{-}5\text{-}units}$, in MWh);
b) Determine the annual electricity generation of the project electricity system, excluding power units registered as CDM project activities (AEG_{total}, in MWh). Identify the set of power units, excluding power units registered as CDM project activities, that started to supply electricity to the grid most recently and that comprise 20.00% of AEG_{total} (if 20.00% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) ($SET_{\geq 20\%}$) and determine their annual electricity generation ($AEG_{SET\text{-}\geq 20\%}$, in MWh);
c) From $SET_{5\text{-}units}$ and $SET_{\geq 20\%}$ select the set of power units that comprises the larger annual electricity generation (SET_{sample});

Identify the date when the power units in SET_{sample} started to supply electricity to the grid. If none of the power units in SET_{sample} started to supply electricity to the grid more than 10 years ago, then use SET_{sample} to calculate the build margin. In this case ignore steps (d), (e) and (f).

Otherwise:

d) Exclude from SET_{sample} the power units which started to supply electricity to the grid more than 10 years ago. Include in that set the power units registered as CDM project activities, starting with power units that started to supply electricity to the grid most recently, until the electricity generation of the new set comprises 20.00% of the annual electricity generation of the project electricity system (if 20.00% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation) to the extent is possible. Determine for the resulting set ($SET_{sample\text{-}CDM}$) the annual electricity generation (AEGSET-sample-CDM, in MWh);

If the annual electricity generation of that set is comprises at least 20.00% of the annual electricity generation of the project electricity system (i.e. $AEG_{SET\text{-}sample\text{-}CDM} \geq 0.2 \times AEG_{total}$), then use the sample group $SET_{sample\text{-}CDM}$ to calculate the build margin. Ignore steps (e) and (f).

e) Include in the sample group $SET_{sample\text{-}CDM}$ the power units that started to supply electricity to the grid more than 10 years ago until the electricity generation of the new set comprises 20.00% of the annual electricity generation of the project electricity system (if 20.00% falls on part of the generation of a unit, the generation of that unit is fully included in the calculation);
f) The sample group of power units m used to calculate the build margin is the resulting set ($SET_{sample\text{-}}$ CDM->10yrs).

The build margin emissions factor is the generation-weighted average emission factor (tCO2/MWh) of all power units m during the most recent year y for which electricity generation data is available, calculated as follows

$$\mathbf{EF_{grid\ BMy} = [\sum_m EG_{,m,y,} * EF_{EL,m,y}] / [\sum_m EG_{my}]}$$

Where:

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

The CO_2 emission factor of each power unit *m* ($EF_{EL,m,y}$) should be determined as per the guidance in Step 4 (a) for the simple OM, using option A2, using for *y* the most recent historical year for which electricity generation data is available, and using for *m* the power units included in the build margin.

If the power units included in the build margin *m* correspond to the sample group $SET_{sample\text{-}CDM\text{-}>10yrs}$, then, as a conservative approach, only option A2 from guidance in Step 4 (a) can be used and the default values provided in Annex 1 of the Tool to Calculate the Emission Factor for an Electricity System shall be used to determine the parameter $\eta_{m,y.}$

Step 6: Calculate the combined margin (CM) emissions factor

The calculation of the combined margin (CM) emission factor ($EF_{grid,CM,y}$) is based on one of the following methods:

a) Weighted average CM; or
b) Simplified CM.

The weighted average CM method (Option a) is used.

a) Weighted average CM

The combined margin emissions factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} * W_{OM} + EF_{grid,BM,y} * W_{BM}$$

Where:

$EF_{grid,BM,y}$	= Build margin CO_2 emission factor in year *y* (tCO_2/MWh)
$EF_{grid,OM,y}$	= Operating margin CO2emission factor in year *y* (tCO2/MWh)
W_{OM}	= Weighting of operating margin emissions factor (%)
W_{BM}	= Weighting of build margin emissions factor (%)

The following default values should be used for w_{OM} and w_{BM}:

W_{OM} = 0.5 and W_{BM} = 0.5 for the first crediting period, and W_{OM} = 0.25 and W_{BM} = 0.75 for the second and third crediting period.

B.6.2. Data and parameters fixed ex ante

Data/Parameter	***Cap$_{BL}$***
Data unit	W
Description	Installed capacity of the hydro power plant before the implementation of the project activity.
Source of data	Project site (as suggested in the Methodology)
Value(s) applied	0
Choice of data or measurement methods and procedures	For new hydro power plants, this value is zero
Purpose of data	Calculation of baseline emissions
Additional comment	-

Data/Parameter	A_{BL}
Data unit	m^2
Description	Area of the single or multiple reservoirs measured in the surface of the water, before the implementation of the project activity, when the reservoir is full in m^2
Source of data	Project site (as suggested in the Methodology)
Value(s) applied	0
Choice of data or measurement methods and procedures	For new reservoirs, this value is zero
Purpose of data	Calculation of baseline emissions
Additional comment	-

Data/Parameter	$EG_{m,y}$
Data unit	MWh
Description	Net electricity generated by power plant / unit m in year *y*
Source of data	COES data from 2010 (Data available in the internet: http://www.coes.org.pe; web link accessed 12/11/2011.)
Value(s) applied	The value is in worksheet (WS-16) BM of the spreadsheet 8 de Agosto DDA OM and BM (Vs3 16.07.2012).xls
Choice of data or measurement methods and procedures	According to the "Tool to Calculate the Emission Factor for an Electricity System" (Version 02.2.1), for ex ante validation calculation, the latest publicly available information is used, which is the COES annual statistics of 2010. Directly measured based on the information provided by COES
Purpose of data	Calculation of baseline emissions
Additional comment	Monitoring frequency: BM: For the first crediting period ex-ante. For the second and third crediting period, only once ex-ante at the start of the second crediting period.

Data/Parameter	$\eta_{m,y}$
Data unit	%
Description	Average net energy conversion efficiency of power unit *m* in year *y*
Source of data	Data from the dispatch centre, COES Annual statistics
Value(s) applied	Net Energy Conversion Efficiencies for all thermal plants are available in the annual statistics of COES. For the *ex-ante* calculation, the latest publicly available information at the time of submission of the CDM-PDD to the DOE for validation is used, which is the COES annual statistics of 2010.
Choice of data or measurement methods and procedures	These Average net energy conversion efficiencies from the dispatch center COES are used for the calculation of the BM emission factor as in terms of vintage of data, project participants have chosen Option 1[50]: For the first crediting period, the BM emission factor is calculated ex-ante based on the most recent information available on units already built for sample group, m, at the time of CDM-PDD submission to the DOE for validation.
Purpose of data	Calculation of baseline emissions
Additional comment	The data from COES is reliable since efficiency is calculated according to the COES procedure Number 17 for the determination of effective power and efficiency of thermal power plants. This procedure established that the efficiency of the plants have to be calculated according to international standards. These calculations and measurements are performed by COES accredited consultants and the result are reviewed and supervised by COES experts

[50] Of Step 5 of the "Tool to Calculate the Emission Factor for an Electricity System" (Version 02.2.1)

Data/Parameter	$EF_{CO2,i,y}$ and $EF_{CO2,m,i,y}$
Data unit	tCO_2/GJ
Description	CO_2 emission factor of fossil fuel type i used in power unit m in year y
Source of data	The following data sources may be used if the relevant conditions apply: IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories
Value(s) applied	IPCC default values: Diesel Oil Residual Fuel Oil Natural Gas Coal
Choice of data or measurement methods and procedures	As there are not local data regarding emission factors, IPCC default values are used. These CO_2 emission factors are used for the calculation of the BM emission factor as in terms of vintage of data, project participants have chosen Option 1[51]: For the first crediting period, the BM emission factor is calculated ex-ante based on the most recent information available on units already built for sample group, m, at the time of CDM-PDD submission to the DOE for validation.
Purpose of data	Calculation of baseline emissions
Additional comment	-

B.6.3. Ex ante calculation of emission reductions

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Project Emissions

The proposed CDM project activity has an installed capacity of 20,567,000 W (20,567 kW), and an hourly regulation reservoir of 216 m^2. The resulting power density of the reservoir is 95,217 W/m^2 (20,567,000 W /216 m^2). This power density significantly exceeds the 10 W/m^2 minimum thresholds required to consider Project emissions from the reservoir negligible.

Baseline Emissions

The baseline emission factor was calculated prior to validation in a transparent and conservative manner as a combined margin (CM) consisting of the average of the operating margin (OM) and the build margin (BM), according to the procedures prescribed in the "Tool to calculate the emission factor for an electricity system", Version 02.2.1, and explained in section B.6.1.

Since the Project itself does not lead to any GHG emissions and no leakage[52] was factored into the calculation of estimated ERs, the baseline emissions were estimated to be equal to the Project ERs.

The net electricity delivery will be calculated using the meter readings from generator 1 and generator 2 and subtracting the auxiliary consumption measured with the 3rd meter. This net

[51] Of Step 5 of the "Tool to Calculate the Emission Factor for an Electricity System" (Version 02.2.1)

[52] Since the energy generating equipment is new and is not replacing any existing facility, the Project does not produce leakage

production will be multiplied by a correction factor leading to the net delivery, which is reflecting the line losses between the plant and the busbar for the electricity dispatch to the SEIN. T

Combined Margin Calculation

Step 1: Identify the relevant electricity systems

The spatial extent of the project boundary is the SEIN. The Project will be connected through a 58.67 km long transmission line at a 138 kV level to the Tingo Maria substation.

Electricity imports from other grids have not been reported, neither by the COES dispatch center or the MINEM. Even if there were imports, for the purpose of determining the OM emission factor, the assumed emission factor for net electricity imports is 0.

Electricity exports to other grids have been reported by the COES dispatch center. Therefore, exports should not be subtracted from electricity generation data used in calculating and monitoring the electricity emission factors.

Step 2: Choose whether to include off-grid power plants in the project electricity system (optional)

Project participants may choose between the following two options to calculate the operating margin and build margin emission factor:

Option I: Only grid power plants are included in the calculation.

Option II: Both grid power plants and off-grid power plants are included in the calculation.

Since project participants considered only grid power plants for the calculation of the operating margin and build margin emission factor, Option I is selected.

Step 3: Select a method to determine the operating margin (OM)

Out of the four options for the OM, the Dispatch Data Analysis OM was selected. The Simple OM method cannot be used since low cost, must-run resources constitute more than 50.00% of total grid generation in Peru.[53]Also it was not necessary to use either the Simple Adjusted OM approach or the Average OM approach because detailed dispatch data is available.

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

For this calculation, the hourly generation in 2010 was used, which was the most recent data available. At the time the Project's Baseline Study was completed, the hourly generation data did not yet exist for one entire year. Therefore, it was assumed that the Project operated at 90% of its capacity (23,274 MW), during all hours of the year. Considering this assumption, the variables were defined as follows:

- $EG_{PJ,y}$: Total electricity displaced by the project activity in year y (MWh) It was estimated at 159,442 MWh in year 2010.

[53] See: COES Annual Statistic (2010), Chart 12.2 and Chart 2.2 A.

- $EG_{PJ,h}$: Electricity displaced by the project activity in hour h of year y (MWh). It was assumed the Project generated at 90% of its installed capacity in each hour.

The following chart shows the $EF_{EL,m,y}$ of all thermal units in the SEIN. Each emission factor has been calculated as per the guidance for the simple OM, using option A2.

Table 13: $EF_{EL,n,y}$ of all thermal units in the SEIN

Thermal Plants (1)	Thermal Plants (2)	Technology (3)	Fuel	n * (4)	EF_{co2} (tCO_2/Gj) (5)	CO_2 Emissions Factor (tCO_2/MWh)
AGUAYTIA TG1-GAS	AGUAYTIA (TG1 TG2)	Gas Turbine Natural Gas	Natural Gas	30.00%	54,300	0.65160
BELLAVISTA MAN 1 - D2	BELLAVISTA	Diesel 2 / Residual	Diesel 2	38.00%	72,600	0.68779
CHICLAYO OESTE -D2	CHICLAYO OESTE (CH-O_SZ1,2,CH-O_GMT1,2,3)	Diesel 2 / Residual	Diesel 2	35.00%	72,600	0.74674
CHILCA 1 TG1-GAS	CHILCA 1 (TG1)	Gas Turbine Natural Gas	Natural Gas	35.00%	54,300	0.55851
CHILCA 1 TG2 -GAS	CHILCA 1 (TG2)	Gas Turbine Natural Gas	Natural Gas	35.00%	54,300	0.55851
CHILCA 1 TG3 -GAS	CHILCA 1 (TG3)	Gas Turbine Natural Gas	Natural Gas	33.00%	54,300	0.59236
CICLO COMBINADO-D2	CHILINA CC	Combined Cycle Gas-Steam	Diesel 2	29.00%	72,600	0.90124
CHILINA TV3-R500	CHILINA (TV1,2,3)	Steam Turbine / Residual	R500	23.00%	75,500	1.18174
CHILINA SULZ 12-R500 D2	CHILINA (SULZ1,2)	Diesel 2 / Residual	Diesel 2	39.00%	72,600	0.67015
CHIMBOTE TG3-D2	CHIMBOTE (CHIM1,3)	Gas Turbine Diesel	Diesel 2	24.00%	72,600	1.08900
OQUENDO TG1 -GAS	CT OQUENDO	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
DOLORES (GM123 ALC 12)-D2	DOLORESPATA	Diesel 2 / Residual	Diesel 2	34.60%	72,600	0.75538
ILO1 CATKATO-D2	ILO CAT	Diesel 2 / Residual	Diesel 2	42.00%	72,600	0.62229
ILO 1 TG2 - D2	ILO 1 (TG1 TG2)	Gas Turbine Diesel	Diesel 2	33.00%	72,600	0.79200
ILO 1 TV2-R500	ILO 1 (TV1, 2,3,4)	Steam Turbine / Residual	R500	34.90%	75,500	0.77880
ILO 2 TV1 -CARB	ILO 2 (TV1)	Steam Turbine / Coal	Coal	40.00%	87,300	0.78570
KALLPA TG1-GAS	KALLPA (TG1)	Gas Turbine Natural Gas	Natural Gas	33.00%	54,300	0.59236
KALLPA TG2-GAS	KALLPA (TG2)	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
KALLPA TG3-GAS	KALLPA (TG3)	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
MALACAS TG4-GAS	MALACAS (TG1 TG2 TG3 TGN4)	Gas Turbine Natural Gas	Natural Gas	27.00%	54,300	0.72400
MOLLENDO 1 2 3-R500	MOLLENDO (MIR1,2,3, TGM1,TGM2)	Diesel 2 / Residual	R500	43.00%	75,500	0.63209
Paramonga	CT PARAMONGA	Cogeneration Bagase/Diesel	Bagase		0	0.00000
PAITA 1-D2	PAITA (PAITEMDS,PAITSKDS)	Diesel 2 / Residual	Diesel 2	34.00%	72,600	0.76871
LFLORES TG1 GAS	CT LAS FLORES	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
PISCO TG1 GAS	CT PISCO (TG1,TG2)	Gas Turbine Natural Gas	Natural Gas	27.00%	54,300	0.72400
INDEPENDENCIA GAS	CT INDEPENDENCIA	Diesel Generator/Natural Gas	Natural Gas	39.00%	54,300	0.50123
PIURA 2 - D2	PIURA (PIURGMT1,2, PIURMAN,PIURMIRRLEES)	Diesel 2 / Residual	Diesel 2	37.00%	72,600	0.70638
SANTA ROSA UTI6-D2	SANTA ROSA (UTI5,6)	Gas Turbine Natural Gas	Natural Gas	30.00%	54,300	0.65160
STA ROSA WEST TG7-D2	SANTA ROSA TG7	Gas Turbine Natural Gas	Natural Gas	33.00%	54,300	0.59236
STAROSA TG8 GAS	SANTA ROSA TG8	Gas Turbine Natural Gas	Natural Gas	35.00%	54,300	0.55851
SAN NICOLAS CUMMINS-D2	SAN NICOLAS (ONAN)	Diesel 2 / Residual	Diesel 2	38.00%	72,600	0.68779
SAN NICOLAS TV3-R500	SAN NICOLAS (TV1 TV2 TV3)	Steam Turbine / Residual	R500	30.00%	75,500	0.90600
SULLANA - D2	SULLANA (SULLALCOS)	Diesel 2 / Residual	Diesel 2	34.00%	72,600	0.76871
TAPARACHI-D2	TAPARACHI	Diesel 2 / Residual	Diesel 2	35.00%	72,600	0.74674
PIURA TG -D2	PIURA TG (PIURTG)	Gas Turbine Diesel	Diesel 2	21.00%	72,600	1.24457
TRUJILLO NORTE-D2	EMERG_NORTE (EMERG)	Diesel 2	Diesel 2	38.00%	72,600	0.68779
TUMBES-R6	TUMBES (MAK1,2)	Diesel 2 / Residual	Residual 6	43.00%	75,500	0.63209
VENTANILLA CCOMB TG3 &TG4-GAS	VENTANILLA (TG3, TG4, TV)	Combined Cycle	Natural Gas	50.00%	54,300	0.39096

YARINACOCHA-R6	YARINACOCHA (WAR1,2,3,4)	Diesel 2 / Residual	Residual 6	39.00%	75,500	0.69692

* η : net energy conversion efficiency

(1) Source: COES. Annual Statisctic 2010. Chart No 4.7.

(2) Source: COES. Hourly Dispatch 2010. Webpage www.coes.org.pe

(3) Source: COES. Annual Statisctic 2010. Chart No 4.7. Technology
(4) Source: COES. Annual Statisctic 2010. Chart No 4.7. Net Efficiency %
(5) See table 2 bellow

Source: IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories

Information on the hourly generation of all plants in the SEIN[54] and their associated emission factors was entered using Excel software and organized in columns where the position of the columns was determined by the grid dispatch merit order. [55] This process enabled identification of the plants that fall within the top x % of grid dispatch each hour of the year. In the *ex-ante* calculations, the quantity of electricity displaced by the project activity during hour, *h,* divided by the total electricity generation in the grid during that hour, *h* is smaller than 10.00%; therefore, 10.00% is used to determine the plants that fall within the top x % of grid dispatch each hour of the year.

The resulting DDA-OM emission factor was calculated as follows:

$EF_{grid,OM\text{-}DD,y} = \sum_h EG_{PJ,h} * EF_{EL,DD,h} / EG_{PJ,y} = 119{,}508.82/159{,}442 = 0.74954 tCO_2/MWh$

Step 5: Calculate the built margin (BM) emission factor

In terms of vintage of data, project participants have chosen Option 1. For the first crediting period, calculate the build margin emission factor ex ante based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation. Any additions to installed capacity in the SEIN were identified and considered. The table below shows the capacity additions to the SEIN and their annual generation. The annual generation of the additions included in this table for prior validation calculations is from 2010, which is the latest year information was publicly available.

Capacity additions from retrofits of power plants should not be included in the calculation of the build margin emission factor.

[54] Data provided by COES, the dispatch center.

[55] This was done by the merit orders assigned to each unit of the SEIN, as published by COES in its annual statistics.

Table 14: Capacity Additions in the SEIN (2006-2010)

Plant	Date	Technology	Installed Capacity Added (MW)	2010 Gen (MWh) of the new addition
CT INDEPENDENCIA	sep-10	Diesel Generator/Natural Gas	22.93	5,270
CT PISCO (TG1,TG2)	aug-10	Gas Turbine Natural Gas	73.20	13,800
C.H. Roncador	apr-10	Hydro	3.80	7,650
CT LAS FLORES	apr-10	Gas Turbine Natural Gas	192.50	13,080
KALLPA (TG3)	feb-10	Gas Turbine Natural Gas	233.00	1,078,300
CT PARAMONGA	dec-09	Cogeneration Bagase/Diesel	23.00	77,480
SANTA ROSA TG8	aug-09	Gas Turbine Natural Gas	193.18	763,860
CHILCA 1 (TG3)	jul-09	Gas Turbine Natural Gas	199.80	930,460
KALLPA (TG2)	jun-09	Gas Turbine Natural Gas	216.00	1,252,340
EMERG_NORTE (EMERG)	jun-09	Diesel 2	64.00	120,970
CT OQUENDO	jan-09	Gas Turbine Natural Gas	31.00	203,600
CHILCA 1 (TG2)	jul-07	Gas Turbine Natural Gas	180.00	406,190
KALLPA (TG1)	jul-07	Gas Turbine Natural Gas	180.00	880,430
CHILCA 1 (TG1)	dec-06	Gas Turbine Natural Gas	174.28	1,092,950
VENTANILLA CCOMB TG3 &TG4-GAS	oct-06	Combined Cycle	457.00	3,214,640
SANTA ROSA (UTI5,6)	aug-06	Gas Turbine Natural Gas	109.80	56,560

In Table 15, it can be seen that the 5 most recently built ($SET_{5\text{-units}}$) plants up to year 2010 were the thermal plants of: (1) CT Independencia, (2) CT Pisco, (3) C.H. Roncador (4), CT Las Flores (5) CT Kallpa (TG3); with their total annual generation being 1,118,100 MWh ($AEG_{SET\text{-}5\text{-}units}$).

On the other hand, the total annual generation of the most recently built plants ($SET_{\geq 20\%}$) accounting for 20.00 % of the grid was higher 6,846,380 MWh ($AEGSET_{\geq 20\%}$), therefore, the most recently built plants accounting for 20.00 % of the grid was selected for the BM calculation

Table 15: Selection of SET_{sample} power plants

Year	Plant Name	Plant Type	Most recent year generation, 2010 (MWh)	Filter most recent 20%	AEGSET-≥20%, (MWh)	Filter 5 most recent units	AEGSET-5-units MWh
sep-10	CT INDEPENDENCIA	Diesel Generator/Natural Gas	5,270	1	5,270	1	5,270
aug-10	CT PISCO (TG1,TG2)	Gas Turbine Natural Gas	13,800	1	13,800	1	13,800
apr-10	C.H. Roncador	Hydro	7,650	1	7,650	1	7,650
apr-10	CT LAS FLORES	Gas Turbine Natural Gas	13,080	1	13,080	1	13,080
feb-10	KALLPA (TG3)	Gas Turbine Natural Gas	1,078,300	1	1,078,300	1	1,078,300
dec-09	CT PARAMONGA	Cogeneration Bagase/Diesel	77,480	1	77,480		
aug-09	SANTA ROSA TG8	Gas Turbine Natural Gas	763,860	1	763,860		
jul-09	CHILCA 1 (TG3)	Gas Turbine Natural Gas	930,460	1	930,460		
jun-09	KALLPA (TG2)	Gas Turbine Natural Gas	1,252,340	1	1,252,340		
jun-09	EMERG_NORTE (EMERG)	Diesel 2	120,970	1	120,970		
jan-09	CT OQUENDO	Gas Turbine Natural Gas	203,600	1	203,600		
jul-07	CHILCA 1 (TG2)	Gas Turbine Natural Gas	406,190	1	406,190		
jul-07	KALLPA (TG1)	Gas Turbine Natural Gas	880,430	1	880,430		
dec-06	CHILCA 1 (TG1)	Gas Turbine Natural Gas	1,092,950	1	1,092,950		
oct-06	VENTANILLA CCOMB TG3 &TG4-GAS	Combined Cycle	3,214,640		-		
aug-06	SANTA ROSA (UTI5,6)	Gas Turbine Natural Gas	56,560		-		
					-		

Total			10,117,580	14	6,846,380	5	1,118,100
					21.73%		
				AEGtotal=	31,510,890		
				AEGSET-≥20%, n=	6,302,178		
	AEGSET-≥20%, MWh		AEGSET-5-units MWh				
	6,846,380	>	1,118,100				

In Table 16 below, the selected sample of most recently built plants was organized by their annual electricity generation output, their weights with respect to the total generation of the selected sample, and their emission factors. By multiplying the emission factor per plant with its assigned weight and then summing up the results, the weighted average of the selected sample was obtained. The resulting **BM** equals **0.56921 tCO_2/MWh** for the year 2010.

Table 16: BM calculation

Plant Name	Most Recent year Generation (MWh)	CO_2 emission Factor tCO_2/MWh
CT INDEPENDENCIA	5,270	0.50123
CT PISCO (TG1,TG2)	13,800	0.72400
C.H. Roncador	7,650	0.00000
CT LAS FLORES	13,080	0.57494
KALLPA (TG3)	1,078,300	0.57494
CT PARAMONGA	77,480	0.00000
SANTA ROSA TG8	763,860	0.55851
CHILCA 1 (TG3)	930,460	0.59236
KALLPA (TG2)	1,252,340	0.57494
EMERG_NORTE (EMERG)	120,970	0.68779
CT OQUENDO	203,600	0.57494
CHILCA 1 (TG2)	406,190	0.55851
KALLPA (TG1)	880,430	0.59236
CHILCA 1 (TG1)	1,092,950	0.55851
Total	**6,846,380**	
$EF_{grid,BM,y}$	**0.56921 tCO_2/MWh**	

Step 6: Calculate the combined margin (CM) emissions factor

The Baseline Emission Factor was calculated as a CM, which is the weighted average[56] of the OM and the BM. All margins are expressed in tCO_2/MWh.

$EF_{grid,CM,y} = EF_{grid,OM,y} * 0.5 + EF_{grid,BM,y} * 0.5$

$EF_{grid,CM,y} = 0.74954 * 0.5 + 0.56921 * 0.5 = 0.65938 tCO_2/MWh$

The resulting Baseline Emission Factor is 0.65938 tCO_2/MWh.

Calculation of the Project's Emission Reductions prior to validation

The estimated annual ERs for the Project were calculated as follows:

ERy = BEy – PEy

Where:

ER_y	=	Emission reductions in year *y* (tCO_2e/yr)
BE_y	=	Baseline emissions in year *y* (tCO_2/yr)
PE_y	=	Project emissions in year *y* (tCO_2e/yr)

$BE_y = EG_{PJ,y} \cdot EF_{grid,CM,y}$

$BE_y = 159,442 MWh * 0.65938 tCO_2/MWh = 105,133 tCO_2$ PEy = 0

Estimated Emission Reductions:

$ER_y = BE_y – PE_y = 105,133 tCO_2 – 0 = 105,133 tCO_2e$

B.6.4. Summary of ex ante estimates of emission reductions

A summary of the ex-ante estimation of ERs can be found in Table below.

Table 17: Ex-ante estimation of the Project's ERs

Year	Baseline emissions (t CO_2e)	Project emissions (t CO_2e)	Leakage (t CO_2e)	Emission reductions (t CO_2e)

[56] The default weights of 50.00%-50.00% were kept

2015	105,133	0	0	105,133
2016	105,133	0	0	105,133
2017	105,133	0	0	105,133
2018	105,133	0	0	105,133
2019	105,133	0	0	105,133
2020	105,133	0	0	105,133
2021	105,133	0	0	105,133
Total	**735,931**	0	0	**735,931**
Total number of crediting years	7			
Annual average over the crediting period	105,133	0	0	105,133

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

Data/Parameter	**$EF_{grid,CM,y}$**
Data unit	tCO_2/MWh
Description	Combined margin CO_2 emission factor for grid connected power generation in year *y* calculated using the latest version of the "Tool to calculate the emission factor for an electricity system"
Source of data	As per the "Tool to calculate the emission factor for an electricity system"
Value(s) applied	0.65938 tCO_2 per MWh for year 2010
Measurement methods and procedures	Ex-post emission factor will be calculated As per the "Tool to calculate the emission factor for an electricity system"
Monitoring frequency	Annual
QA/QC procedures	As per the "Tool to calculate the emission factor for an electricity system"
Purpose of data	Calculation of baseline emissions
Additional comment	The parameters defined in the tool have been included in this section of the PDD. The data will be archived electronically. Archived data will be kept during the crediting period and two years later

Data/Parameter	**$EG_{facility,y}$ ($EG_{pj,y}$)**
Data unit	MWh/yr
Description	Quantity of net electricity generation supplied by the project plant/unit to the grid in year *y*
Source of data	Project records and/or COES.
Value(s) applied	159,442

Measurement methods and procedures	The project will employ three independent meters at the low voltage side of the 13.8kV-22.9kV/138kV step up transformer (one at each generator and one for the auxiliary consumption). These meters will be used to monitor the net energy delivered to the SEIN by the Project. Sales reports of the electricity supplied to the SEIN by the Project will be issued based on the readings from these meters. The net delivery will be calculated using the meter readings from generator 1 and generator 2 and subtracting the auxiliary consumption measured with the 3rd meter. This net production will be multiplied by a correction factor leading to the net delivery, which is reflecting the line losses[57] between the plant and the busbar for the electricity dispatch to the SEIN. $\mathbf{EG_{facility,y}\ (EG_{pj,y})} = \sum_h \mathbf{EG_{PJ,h}}$
Monitoring frequency	Continuous monitoring, hourly measurement and monthly recording. Measurements are undertaken using energy meters.
QA/QC procedures	Cross check measurement results with records for sold electricity and information from COES. The metering system will be calibrated according to the manufacturer specifications and at least every 3 years.
Purpose of data	Calculation of baseline emissions
Additional comment	The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	$\mathbf{EG_{n,h}}$
Data unit	MWh
Description	Net electricity generated and delivered to the grid by power plant / unit n in hour *h*
Source of data	COES
Value(s) applied	COES data from 2010 (Data available in the internet: http://www.coes.org.pe; web link accessed 12/11/2011.)
Measurement methods and procedures	Directly measured and/or based on the information provided by COES. The proportion of data to be monitored is 100% and the data will be archived electronically.
Monitoring frequency	Annual
QA/QC procedures	
Purpose of data	Calculation of baseline emissions

[57] The line losses are being determine on an annual basis by an independent service provider. The line loss factor is then submitted and accepted by COES. Any electricity dispatch will be corrected with the loss factor, which takes into account the 58.67 km transmission line. The line loss factor for 2018 has been 0.9823.

Additional comment	Monitoring frequency: o Dispatch data OM: hourly The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**$EG_{PJ,h}$**
Data unit	MWh
Description	Electricity displaced by the project activity in hour h of year y
Source of data	Project records and/or COES. .
Value(s) applied	18.20118 MWh Data used is presented in the spreadsheet for Grid Emission Factor calculation
Measurement methods and procedures	The project will employ three independent meters at the low voltage side of the 13.8kV-22.9kV/138kV step up transformer (one at each generator and one for the auxiliary consumption). These meters will be used to monitor the net energy delivered to the SEIN by the Project. Sales reports of the electricity supplied to the SEIN by the Project will be issued based on the readings from these meters.
Monitoring frequency	The readings of the electricity meters will be continuously measured and recorded hourly. The proportion of data to be monitored is 100.00% and the data will be archived electronically. The electric meters will be implemented according to the dispatch center (COES) requisites.[59]
QA/QC procedures	Sales records to the SEIN (provided by COES dispatch center) or to the final client, as well as other records are used to ensure consistency. Electricity supplied by the project activity to the grid. The electric meters will be implemented according to the dispatch center (COES) requisites, which currently requires that the metering system shall be at least Class 0.2 compliant in metering accuracy. The metering system will be calibrated according to the manufacturer specifications and at least every 3 years.
Purpose of data	Calculation of baseline emissions

[59] See: Procedimieto Tecnico del Comite de Operacion Economica del SINAC. PR – 20 Verificacion del Cumplimiento de Requisitos para ser integrante del COES SINAC, p. 20; in the internet: http://www.coes.org.pe/coes/Procedimientos/procedimiento_n20.pdf , link accessed on 12/11/2011.

Additional comment	The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**$EG_{8\ de\ Agosto,h}$**
Data unit	MWh
Description	Electricity generated and delivered to the grid by power unit 8 de Agosto in hour h.
Source of data	Project records and/or COES.
Value(s) applied	18.20118 MWh
Measurement methods and procedures	The readings of the electricity meters will be continuously measured and recorded hourly. The proportion of data to be monitored is 100.00% and the data will be archived electronically. The electric meters will be implemented according to the dispatch center (COES) requisites.
Monitoring frequency	Annual
QA/QC procedures	The electric meters will be implemented according to the dispatch center (COES) requisites, which currently requires that the metering system shall be at least Class 0.2 compliant in metering accuracy. The metering system will be calibrated according to the manufacturer specifications and at least every 3 years.
Purpose of data	Calculation of baseline emissions
Additional comment	The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**$\eta_{m,y}$**
Data unit	%
Description	Average net energy conversion efficiency of power unit ,*m* in year, *y*
Source of data	Data from the dispatch center, COES annual statistics (Data available in the internet: http://www.coes.org.pe; web link accessed 12/11/2011.)
Value(s) applied	Net Energy Conversion Efficiencies for all thermal plants are available in the annual statistics of COES. For the *ex-ante* calculation, the latest publicly available information is used, which is the COES annual statistics of 2010.
Measurement methods and procedures	In the first monitoring report will be used the last available annual report of COES. This information will be monitored once during the crediting period.
Monitoring frequency	Annual

QA/QC procedures	The data from COES is reliable since efficiency is calculated according to the COES procedure Number 17 for the determination of effective power and efficiency of thermal power plants. [60] This procedure established that the efficiency of the plants have to be calculated according to international standards. For diesel engines ISO-3046-1 or its updated versions, for gas turbines: section 8 of ISO 2314: 1989 or its updated versions, for steam turbines: DIN1943, Sections 6 a 8, February 1975, or it updated version etc. These calculations and measurements will be performed with a COES accredited consultants and the result are reviewed and supervised by COES experts.
Purpose of data	Calculation of baseline emissions
Additional comment	The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**Merit Order**
Data unit	Text
Description	The merit order in which power plants are dispatched by documented evidence
Source of data	COES (Data available in the internet: http://www.coes.org.pe; web link accessed 12/11/2011.)
Value(s) applied	Information is available to the DOE in Excel spreadsheets based on information provided by COES.
Measurement methods and procedures	The merit order is publicly available in the annual statistics of COES. For each year, it displays the variable cost of thermal plants from the SEIN in effect at December. The proportion of data to be monitored is 100% of all plants in the merit order. The data will be archived electronically and in paper for original documents. The merit order will base on most recent available information in each monitoring period.
Monitoring frequency	yearly
QA/QC procedures	-
Purpose of data	Calculation of baseline emissions
Additional comment	The plants should be stacked in the dispatch data analysis. The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**Cap $_{PJ}$**
Data unit	W
Description	Installed capacity of the hydropower plant after the implementation of the project activity.
Source of data	Project site.

[60] See in the internet: http://www.coes.org.pe/coes/Procedimientos/procedimiento_n17.pdf; web link accessed on 12/11/2011.

Value(s) applied	19,000,000 W
Measurement methods and procedures	As indicated on the manufacture´s nameplate. The monitoring frequency would be yearly.
Monitoring frequency	yearly
QA/QC procedures	Cross check with the annual statistic of COES available.
Purpose of data	Calculation of baseline emissions
Additional comment	The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**A_{pj}**
Data unit	m^2
Description	Area of the reservoir measured in the surface of the water, after the implementation of the project activity, when the reservoir is full
Source of data	Project site
Value(s) applied	The area of the new single or multiple reservoirs measured in the surface of the water, after the implementation of the project activity, when the reservoir is full will be 216 m^2.
Measurement methods and procedures	The area of the single or multiple reservoirs measured in the surface of the water, after the implementation of the project activity, when the reservoir is full will be monitoring with “as- built” map of the reservoir.
Monitoring frequency	yearly
QA/QC procedures	
Purpose of data	Calculation of baseline emissions
Additional comment	The data will be archived electronically. Archived data will be kept during the crediting period and two years later.

Data/Parameter	**$EF_{CO2,i,y}$ and $EF_{CO2,m,i,y}$**
Data unit	tCO_2/GJ
Description	CO_2 emission factor of fossil fuel type i used in power unit m in year y

<table>
<tr><td>Source of data</td><td>The following data sources may be used if the relevant conditions apply:

<table><tr><th>Data source</th><th>Conditions for using the data source</th></tr><tr><td>Values provided by the fuel supplier of the power plants in invoices</td><td>If data is collected from power plant operators (e.g. utilities)</td></tr><tr><td>Regional or national average default Values</td><td>If values are reliable and documented in regional or national energy statistics / energy balances</td></tr><tr><td>IPCC default values at the lower limit of the uncertainty at a 95.00% confidence interval as provided in table 1.4 of Chapter1 of Vol. 02 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories</td><td></td></tr></table></td></tr>
<tr><td>Value(s) applied</td><td><table><tr><th colspan="2">IPCC default values: Diesel Oil</th></tr><tr><td>Residual Fuel Oil Natural Gas</td><td>72,600</td></tr><tr><td>Coal</td><td>75,500</td></tr><tr><td>IPCC default values: Diesel Oil</td><td>54,300</td></tr><tr><td>Residual Fuel Oil Natural Gas</td><td>87,300</td></tr></table></td></tr>
<tr><td>Measurement methods and procedures</td><td>Dispatch data OM: Annually for the year y in which the project activity is displacing grid electricity or, if available, hourly. Further guidance can be found in Step 3 of the Tool to calculate the emission factor for an electricity system;
BM: For the first crediting period only once ex –ante, following the guidance included in Step 5 of the “Tool to calculate the emission factor for an electricity system”. For the second and third crediting period, only once ex ante at the start of the second crediting period</td></tr>
<tr><td>Monitoring frequency</td><td>Annual</td></tr>
<tr><td>QA/QC procedures</td><td>-</td></tr>
<tr><td>Purpose of data</td><td>Calculation of baseline emissions</td></tr>
<tr><td>Additional comment</td><td>The data will be archived electronically. Archived data will be kept during the crediting period and two years later.</td></tr>
</table>

B.7.2. Sampling plan

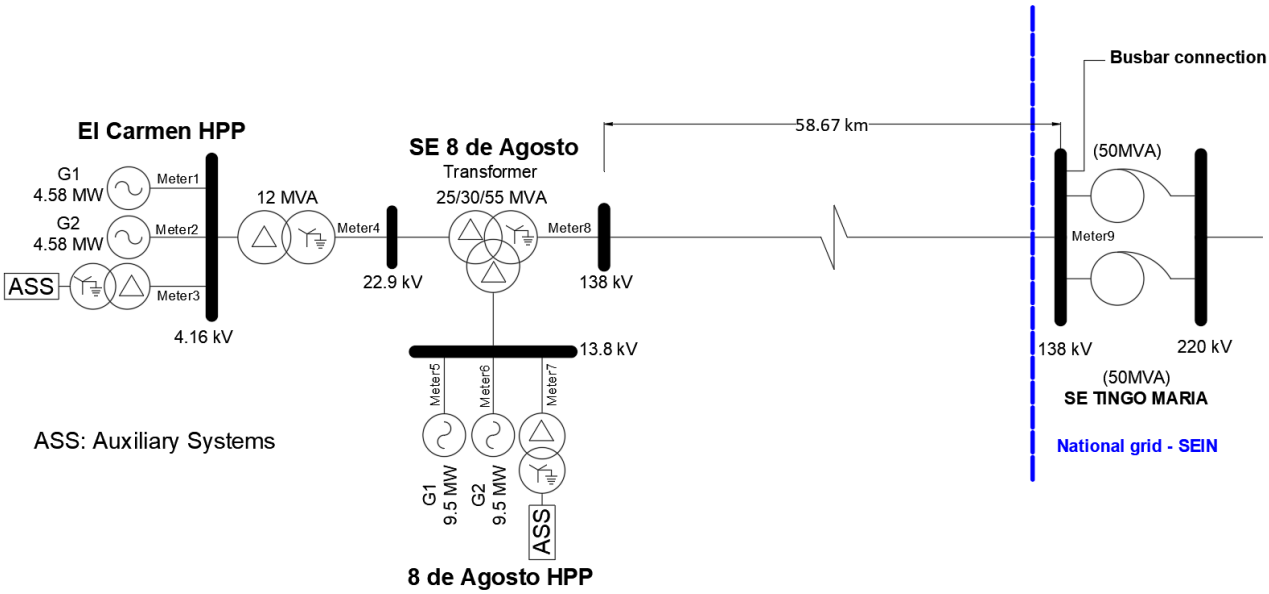
>>

Not applicable.

B.7.3. Other elements of monitoring plan

>>

The installed meters of the plant as described above are being shown in the following schematic diagram.



SECTION C. Start date, crediting period type and duration

C.1. Start date of project activity

>>

28/02/2013. The estimated date when the Project reaches financial closing, which constitute the date on which the project participants will commit to expenditures related to the implementation or related to the construction of the project activity.

C.2. Expected operational lifetime of project activity

>>

The Project is expected to have a minimum operating life of 30 years.

C.3. Crediting period of project activity

C.3.1. Type of crediting period

>>

The proposed project uses Renewable crediting period.

C.3.2. Start date of crediting period

>>

01/01/2016

C.3.3. Duration of crediting period

>>

7 years, renewable twice,

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

>>

In the case of Peru, according to the updated Electric Concessions Law (Law No. 25844),[61] for the development of hydroelectric power plants of over 500 kW a concession is required (Article 3), however when the generation is undertaken with renewable resources and is less than 20MW, the presentation of an Environmental Impact Assessment (EIA) is not required (Article 38) since the impacts are not considered significant. Nevertheless, a preliminary environmental impact assessment for the power plant was developed for the feasibility study of the Project.

D.2. Environmental impact assessment

>>

Environmental impacts identified by the study were not considered to be significant. In addition, the study states that the environmental impact is considered not significant since the Project will not modify the natural watercourse. The preliminary impact assessment study details potential environmental impacts (positive and negative) in the different stages of the project:

Construction Stage

- Minor impact on geomorphological alterations during the construction phase
- Moderate impacts on geomorphological alterations by activities like adduction excavation systems, construction of the power house and drilling the penstock
- Moderate impact on erosion of the earth by activities such as mobilization of personal, equipment and material, enabling access, clearing land and vegetation, adduction excavation systems, construction of power house and opening and functioning surplus material deposits, drilling the penstock, use and maintenance of vehicles and machinery, closing material deposits and quarries.
- Minor impact on the water quality (no impact on ecological flow)
- Minor impact on the quality of air.
- Moderate impact on the quality of air by activities such as adduction of excavation systems, construction of the power house, opening and functioning of surplus material deposits, drilling the penstock
- Minor impact on quality of landscape
- Moderate impact on quality of landscape by activities such as adduction excavation systems, construction of power house, and drilling the penstock
- Minor impact on flora alteration.
- Moderate impact on flora and fauna alteration by activities such adduction

[61] See in the internet: http://www2.osinerg.gob.pe/MarcoLegal/pdf/LEYCE-DL25844.pdf; web link accessed on 10/11/2011.

excavation systems, construction of power house, and testing and implementation of the plant.
- High impact on flora alteration by drillings for the penstock
- Minor alteration on ecosystems.
- Moderate impact on ecosystems by adduction excavation systems, construction of power house, and drillings for the penstock
- Minor impact on social conflicts

\+ Generation of jobs opportunities
\+ Increase in the economic dynamic of the surrounding areas since they have the opportunity to provide different goods and services.
\+ Improve surrounding areas through payments of taxes

Operation Stage

- Minor impact on geomorphological alterations during the operation phase
- Only moderate impact on geomorphological alterations by activities such as the turbine water discharge and maintenance and cleaning of structures.
- Minor impact on the quality and erosion of the earth
- Moderate impact on erosion of the earth by activities such as operation of the conduction pipe, turbine water discharge, and maintenance and clearing of structures
- Moderate impact on the quality of the water by activities such as the operation of the intake, turbine water discharge, functioning of administrative offices.
- Moderate impact on the ecological flow by activities such as the operation of the intake, turbine water discharge, and maintenance and cleaning from structures.
- Moderate impact on the quality and noise of the air.
- Minor impact on la quality of the landscape and on the flora.
- Moderate impact on the fauna nad hydrobiology
- Moderate impact on the ecosystems
- Minor impacts on social conflicts

\+ Generation of jobs opportunities
\+ Increase in the economic dynamic of the surrounding areas since they have the opportunity to provide different goods and services.
\+ Improve surrounding areas through payments of taxes

A set of mitigation, restoration, prevention and correction measures are listed in the document in order to minimize negative impacts and increase the effects of the positive ones. Finally, the study recommends the implementation of the Project due to it being a clean energy project with the possibility to be implemented in a sustainable way.

1. Impacts to the Physical Environment

Impacts	Mitigation Measure
Alteration of the surface due to: - Soil preparation, excavation and ground movement - dust lifting, soil erosion, soil pollution - slope instability	All the construction work and soil excavation shall be limited to an area to minimize the risks in the close areas. The superficial soil removed shall be located in selected deposit zone and it could be reused as material during the construction phase. Avoidance of slope instability
Potential noise development	The levels of noise shall not exceed 80dB during the day and 70 dB during the night, as set forth in the National Standards of the environmental quality for the noise DS-085-2003-PCM.
	The areas that need hearing protection will be delimited.
Potential impact on water resources due to: - Change on the water flow, quality of the water of the river	There shall be a strict control of material movements in the bed of the watercourses. Machinery maintenance such as oil change or washing machines shall be supervised and done in a sealed area as applicable and far enough from the river channel in order to avoid spills. .

2. Impacts on the Biotic Environment

Impacts	Mitigation Measure
Vegetation (Flora) - Construction of roads of access and structures - Loss of wildland, soil and flora - Changes on the existent vegetation	All the construction work and soil excavation shall be limited to an area to minimize the risks in the close areas. The organic soil shall be stored in a safe area for its reutilization. Once the construction is finished, the recuperation of the affected land shall be done as soon as possible

Fauna - Disturbance of the wildlife due to the noise	All the construction work and soil excavation shall be limited to an area to minimize the risks in the close areas. The disturbance of the wildlife located outside the limited area project shall be avoided. The food waste shall be keep on closed containers.

SECTION E. Local stakeholder consultation

E.1. Modalities for local stakeholder consultation

>>

The project sponsor assigned the National Environment Fund (FONAM)[62] to undertake the local stakeholder consultation for the Project. The objectives of this consultation were:

(i) to identify the project´s area of influence, the main stakeholders and affected people;

(ii) to identify and describe the current social, economic and environmental situation within the Project's influence area;

(iii) to inform the local stakeholders of the proposed project and its characteristics as CDM project;

(iv) to inform the local stakeholder of the Project, as well as the following topics: conservation of the environment, the impact of local global pollution on people, climate change, the greenhouse gas effect and the Clean Development Mechanism;

(v) to define the social investment strategy for the Project.

The Project's influence area was defined by FONAM as the area around the project within a radius of 10 km. Once this zone of influence was established FONAM identified the main stakeholders through on-site visits as well as documents such as the preliminary environmental impact assessment, national statistics and technical studies. The direct influence area identified includes the locations of Maravillas, Caunarapa and Nuevo Chiapaco located at Monzon District.

FONAM developed a survey and distributed it to 262 local people in order to get information about their economic situation, living conditions as well as to gauge local knowledge about the Project and environmental issues such as climate change. FONAM also held a total of 25 interviews with local authorities to collect information about environment problems and local social characteristics.

[62] FONAM is an independent none for profit organization established through congressional legislation for promoting private and public environmental investments. See in the internet: www.fonanmperu.org; web linked accessed on 12/11/2011

Also these interviews were used to know if local authorities were aware about the Project and to listen their concerns about it.

To prepare for the information workshops, an informative brochure about the Project was developed by FONAM, as well as some flipcharts about global environmental issues and the Project activity. The authorities and representatives of the communities were then sent written invitations to the workshop and among the other diffusion measures undertaken to invite the population to the final workshop were flyers that were handed out at different hours and posters.

Three information workshops were held, one on Caunarapa on 04/09/2011, other one on Chipaco on 09/09/2011 and the third one on San Benito on 09/09/2011. After these workshops, a local consultation workshop was held in Maravillas on 11/09/2011. During these workshops, FONAM and the project sponsor explained the scope and the environmental contribution of the Project including an explanation of the CDM and climate change. Also, in these workshops local concerns and comments were discussed. During the local consultation workshop project sponsors and FONAM address the main concerns of the local population and present the main elements of the social investment plan of the Project

The table below summarizes the different workshops held including the amount of people in attendance:

Table 18: Local consultation workshops

Workshop	Assistance	Date
Community of Caunarapa	19 inhabitants	04/09/2011
Community of Chipaco	13 mothers and school professors 18 school students	09/09/2011
Community of San Benito	9 mothers and school professors	09/09/2011
Local consultation workshop in Maravillas	148 inhabitants	11/11/2011

All this information was compiled in the FONAM's Local Stakeholder Consultation report. The report includes the list of participants, the minutes and the social investment plan

E.2. Summary of comments received

>>

The Project has been received positively by the local stakeholders. Most of the villagers knew about the project; they think that the project is an opportunity to improve the local economy and it will give employment opportunities.

All the people interviewed agreed that their major concerned is the necessity of water and sewer service. As well, they requested for the improvement of infrastructures of schools and medical centers, agricultural technification support and the construction of a new main square.

The comments of the final workshop are:

- The municipal agent, mentioned his concern about the final use of the land where the project takes place, as well as the widening of the highway and the building of a footbridge.
- The lieutenant governor, asked about the employment opportunities for the population of 8 de Agosto village.

- A community representative, asked for the amount of tax transfer to the region due to the development of the hydropower project and for the assistance to improve the welfare of the village.

E.3. Consideration of comments received

>>

The comments and questions were discussed and answered thoroughly as explained bellow by the representatives of the Project:

- The project shall build a footbridge;
- The project shall support the community center;
- The project shall installation of a communication antenna;
- During construction it is planned to hire local workers as applicable;
- The tax transfer to the region is established by law and represents 1.00 % of the Project's revenues. At this stage it is not possible to calculate the exact amount that will be transferred to the region; and

The project developer shall assist the community to formalize land property.
The comments of the local stakeholders were taken into account and have been considered in the elaboration of a social investment plan. This social investment plan is going to be financed with parts of the revenues obtained by selling the CERs generated by the Project. The social investment plan is listed in FONAM's Local Stakeholder Consultation report.

Commitments of the social investment plan:

- For Caunarapa town :S/15,000for water and drainage studies and land purchase
- For Aucantagua town : S/48,000 to support the construction of the community center and wean land
- For 8 de Agosto : S/88,000 to support a community center, footbridge and wean land
- Installation of a communication antenna: S/40,000

The commitments of the social investment plan for the Project foresees that 191,000 S./ will be distributed to the region during the first 7 years of obtained revenues from the sales of CERs generated by the Project.

SECTION F. Approval and authorization

>>

All Letters of Approvals of Parties involved have been made available to the DOE at the time of validation. Each Project Participant involved has been authorized by at least one Party involved in the project activity in the respective letter of approval or in a separate authorization letter

1. Contact information of project participants

Organization name	Generación Andina S.A.C.
Country	Peru
Address	Avenida Ricardo Palma 341, oficina 503, Miraflores
Telephone	-
Fax	-
E-mail	gviera@polarisenergyperu.com
Website	-
Contact person	Gabriel Viera Cherro

2. Affirmation regarding public funding

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

3. Applicability of methodologies and standardized baselines

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4. Further background information on ex ante calculation of emission reductions

Table 19: EF_{EL} calculations 2010 below shows EF_{EL}s calculations with actual 2010 NECs ($\eta_{m,y}$ Average net energy conversion efficiency of power unit ,m in year, y) from the Annual Statistics published by COES. In the monitoring, EF_{EL}s should be updated using the latest Annual Statistics.

Table 19: EF_{EL} calculations 2010

Thermal Plants (1)	Thermal Plants (2)	Technology (3)	Fuel	η * (4)	EF_{co2} (tCO_2/Gj) (5)	CO_2 Emissions Factor (tCO_2/MWh)
AGUAYTIA TG1-GAS	AGUAYTIA (TG1 TG2)	Gas Turbine Natural Gas	Natural Gas	30.00%	54,300	0.65160
BELLAVISTA MAN 1 - D2	BELLAVISTA	Diesel 2 / Residual	Diesel 2	38.00%	72,600	0.68779
CHICLAYO OESTE -D2	CHICLAYO OESTE (CH-O_SZ1,2,CH-O_GMT1,2,3)	Diesel 2 / Residual	Diesel 2	35.00%	72,600	0.74674
CHILCA 1 TG1-GAS	CHILCA 1 (TG1)	Gas Turbine Natural Gas	Natural Gas	35.00%	54,300	0.55851
CHILCA 1 TG2 -GAS	CHILCA 1 (TG2)	Gas Turbine Natural Gas	Natural Gas	35.00%	54,300	0.55851
CHILCA 1 TG3 -GAS	CHILCA 1 (TG3)	Gas Turbine Natural Gas	Natural Gas	33.00%	54,300	0.59236
CICLO COMBINADO-D2	CHILINA CC	Combined Cycle Gas-Steam	Diesel 2	29.00%	72,600	0.90124
CHILINA TV3-R500	CHILINA (TV1,2,3)	Steam Turbine / Residual	R500	23.00%	75,500	1.18174
CHILINA SULZ 12-R500 D2	CHILINA (SULZ1,2)	Diesel 2 / Residual	Diesel 2	39.00%	72,600	0.67015
CHIMBOTE TG3-D2	CHIMBOTE (CHIM1,3)	Gas Turbine Diesel	Diesel 2	24.00%	72,600	1.08900
OQUENDO TG1 -GAS	CT OQUENDO	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
DOLORES (GM123 ALC 12)-D2	DOLORESPATA	Diesel 2 / Residual	Diesel 2	34.60%	72,600	0.75538
ILO1 CATKATO-D2	ILO CAT	Diesel 2 / Residual	Diesel 2	42.00%	72,600	0.62229
ILO 1 TG2 - D2	ILO 1 (TG1 TG2)	Gas Turbine Diesel	Diesel 2	33.00%	72,600	0.79200
ILO 1 TV2-R500	ILO 1 (TV1, 2,3,4)	Steam Turbine / Residual	R500	34.90%	75,500	0.77880

ILO 2 TV1 -CARB	ILO 2 (TV1)	Steam Turbine / Coal	Coal	40.00%	87,300	0.78570
KALLPA TG1-GAS	KALLPA (TG1)	Gas Turbine Natural Gas	Natural Gas	33.00%	54,300	0.59236
KALLPA TG2-GAS	KALLPA (TG2)	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
KALLPA TG3-GAS	KALLPA (TG3)	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
MALACAS TG4-GAS	MALACAS (TG1 TG2 TG3 TGN4)	Gas Turbine Natural Gas	Natural Gas	27.00%	54,300	0.72400
MOLLENDO 1 2 3-R500	MOLLENDO (MIR1,2,3, TGM1,TGM2)	Diesel 2 / Residual	R500	43.00%	75,500	0.63209
Paramonga	CT PARAMONGA	Cogeneration Bagase/Diesel	Bagase		0	0.00000
PAITA 1-D2	PAITA (PAITEMDS,PAITSKDS)	Diesel 2 / Residual	Diesel 2	34.00%	72,600	0.76871
LFLORES TG1 GAS	CT LAS FLORES	Gas Turbine Natural Gas	Natural Gas	34.00%	54,300	0.57494
PISCO TG1 GAS	CT PISCO (TG1,TG2)	Gas Turbine Natural Gas	Natural Gas	27.00%	54,300	0.72400
INDEPENDENCIA GAS	CT INDEPENDENCIA	Diesel Generator/Natural Gas	Natural Gas	39.00%	54,300	0.50123
PIURA 2 - D2	PIURA (PIURGMT1,2, PIURMAN,PIURMIRRLEES)	Diesel 2 / Residual	Diesel 2	37.00%	72,600	0.70638
SANTA ROSA UTI6-D2	SANTA ROSA (UTI5,6)	Gas Turbine Natural Gas	Natural Gas	30.00%	54,300	0.65160
STA ROSA WEST TG7-D2	SANTA ROSA TG7	Gas Turbine Natural Gas	Natural Gas	33.00%	54,300	0.59236
STAROSA TG8 GAS	SANTA ROSA TG8	Gas Turbine Natural Gas	Natural Gas	35.00%	54,300	0.55851
SAN NICOLAS CUMMINS-D2	SAN NICOLAS (ONAN)	Diesel 2 / Residual	Diesel 2	38.00%	72,600	0.68779
SAN NICOLAS TV3-R500	SAN NICOLAS (TV1 TV2 TV3)	Steam Turbine / Residual	R500	30.00%	75,500	0.90600
SULLANA - D2	SULLANA (SULLALCOS)	Diesel 2 / Residual	Diesel 2	34.00%	72,600	0.76871
TAPARACHI-D2	TAPARACHI	Diesel 2 / Residual	Diesel 2	35.00%	72,600	0.74674
PIURA TG -D2	PIURA TG (PIURTG)	Gas Turbine Diesel	Diesel 2	21.00%	72,600	1.24457
TRUJILLO NORTE-D2	EMERG_NORTE (EMERG)	Diesel 2	Diesel 2	38.00%	72,600	0.68779
TUMBES-R6	TUMBES (MAK1,2)	Diesel 2 / Residual	Residual 6	43.00%	75,500	0.63209
VENTANILLA CCOMB TG3 &TG4-GAS	VENTANILLA (TG3, TG4, TV)	Combined Cycle	Natural Gas	50.00%	54,300	0.39096
YARINACOCHA-R6	YARINACOCHA (WAR1,2,3,4)	Diesel 2 / Residual	Residual 6	39.00%	75,500	0.69692

* η : net energy conversion efficiency

(1) Source: COES. Annual Statisctic 2010. Chart No 4.7.

(2) Source: COES. Hourly Dispatch 2010. Webpage www.coes.org.pe

(3) Source: COES. Annual Statisctic 2010. Chart No 4.7. Technology
(4) Source: COES. Annual Statisctic 2010. Chart No 4.7. Net Efficiency %
(5) See table 2 bellow

Source: IPCC default values at the lower limit of the uncertainty at a 95% confidence interval as provided in table 1.4 of Chapter1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories

Table 19: EF_{EL} calculations 2010 above has the emission factor formulas inserted in it. Actual (Average net energy conversion efficiency of power unit m in year y = **ηm,y**), as well as data on technology and fuel were obtained from COES. All this data was publicly available at the COES website in its annual statistics. The specific information source is the chart entitled “Costos Variables de las Centrales Termoeléctricas del SEIN”, which appeared in the COES Annual Statistics (*Estadística anual de Operaciones*) for the year 2010 as chart number 4.7.

Justification of the usage of COES information system data for baseline calculation:

In the baseline calculation, data that is not registered by COES has been disregarded and only COES data is considered to be the best approximation of total SEIN data, for both generation and installed capacity additions. Moreover, COES data is deemed to allow for good monitoring practices because:

1. There is no better quality data of the SEIN production than what is collected by COES. The information of plants connected to the SEIN but not registered in COES regarding generation and installed capacity additions is provided by the plants’ management periodically to the MINEM. However, this data does not pass through a verification or validation process, nor is it required to comply with technical standards as rigorously as COES requires from their power plant members;
2. The limitation of MINEM’s final annual reports and data availability, such as the lack of hourly dispatch data, would not allow for good monitoring practice;

3. The generation of these other plants connected to the SEIN but not registered by COES, is irrelevant as it comprised only 3.00% of total SEIN electricity generation in 2010, as Table 20: Generation in SEIN and COES below shows.

Table 20: Generation in SEIN and COES

	SEIN (GWh)	COES (GWh)	COES/SEIN	Not recorded by COES
2010	33,326	32,427	0.97	0.03
2009	30,493	29,807	0.98	0.02
2008	30,104	29 559	0.98	0.02
2007	27,806	27,255	0.98	0.02
2006	25,251	24,762	0.98	0.02
2005	23,434	23,001	0.98	0.02
2004	22,288	21,903	0.98	0.02
2003	20,999	20,689	0.99	0.01
2002	20,018	19,658	0.98	0.02
2001	18,755	18,463	0.98	0.02
Source: *Anuario Estadístico MINEM*, 2001 - 2010 *and Estadística de Operaciones*, COES, 2001 – 2010.				

5. Further background information on monitoring plan

I. Background information

II. Purpose of the Monitoring Plan

III. Use of the Monitoring Plan by the Operator

IV. Organizational, Operational and Monitoring Obligations
- A. Obligations of the Operator
- B. Emissions Reductions Calculation Procedure and Required Spreadsheets
- C. Other parameters

V. Annexes

The ERCP Organizational Structure and Quality Assurance and Control Procedure

I. Background Information

The baseline methodology and monitoring methodology for the Project are in accordance with the approved consolidated baseline methodology (ACM0002. Version 13.0.0): “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” (The Baseline Methodology).

II. Purpose of the Monitoring Plan

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. This report presents the Monitoring Plan (MP) for the Project. 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 CDM of the Kyoto Protocol.

III. Use of the Monitoring Plan by the Project Operator

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 in the monitoring period. Adherence to the instructions in the MP is necessary for the Project Operator to successfully measure and track the impact of the Project, and to prepare all data required for the periodic audit and verification process that must be undertaken to confirm the attainment of the corresponding ERs.

IV. 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 by the project operator (the Operator) throughout the crediting period of the Project. The Operator is obligated to ensure that sufficient and accurate information is available to calculate ERs in a transparent manner, and that adequate information is collected and maintained to facilitate successful verification of accounted ERs.

Key responsibilities: The steering committee will approve the monitoring reports. ERCP Management will be in charge of emission reduction calculation and will report to the steering committee. This organizational structure for this activity is included in the monitoring plan in the “Emissions Reductions Calculation Procedure (ERCP) Organizational Structure”.

Training of monitoring personnel: The team established in the ERCP Organizational structure, and composed of the MP Steering Committee and the ERCP Management, will be trained in a one day workshop on a comprehensive set of tools and knowledge required to implement the monitoring plan including: (a) accurate monitoring of the performance and output characteristics of the plant to record and keep accurate data; (b) collection and integration of utility data for the current year; (c) incorporation of these data sets into spread sheets, and (d) consistently calculating verifiable CERs as a function of measured plant output against a current-year emission factor that serves as a recognized proxy for emissions displaced from the grid. The training on the MP and associated responsibilities will build the capability of the MP Steering Committee and the ERCP Management to replicate, on an *ex-post* basis, an equivalent process that has been

demonstrated in this PDD for an *ex-ante* emissions avoidance calculation as if the plant were in operation in 2010.

Equipment Required: Adequate computer services and file storage are required, and maintenance of computers and data contained therein are described under the following section. Adequate metering and logging equipment will be procured for measuring electricity generation by the plant, and net levels of electricity dispatched for sale to the grid. The electric meter will be implemented according to the dispatch center (COES) requisites.[63]Procedures for maintenance and installation of the equipment, as well as calibration, will be performed according to manufacturer specifications of the equipment. The periodic calibration would be performed at least every 3 years. All measurements, data gathering, record keeping, and procedures for dealing with possible monitoring data adjustments will be performed in specific consideration of the data gathering requirements of the MP and as determined as adequate for meeting the baseline and monitoring requirements described in baseline methodology ACM0002 version 13.0.0 and the *Tool to Calculate the Emission Factor for an Electricity System (Version 02.2.1)*.

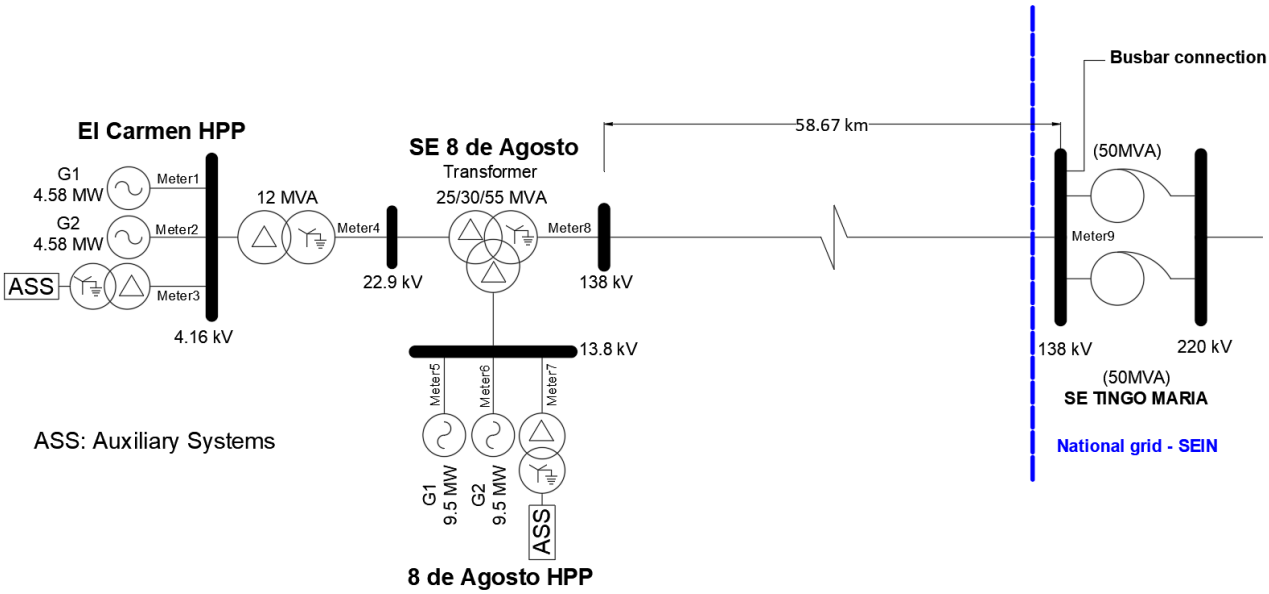
In addition, the dispatch center, COES, occasionally performs a similar quality control check. The accuracy of the electricity meters is a demand not only from COES but also from final customers in regard to their energy purchase contracts.

In total four meters will be employed at the power plant and one meter at the Tingo Maria substation. One meter is placed at each generator and one is used for the auxiliary consumption – all measuring at 13.8 kv. Another meter is placed at the “8 de Agosto” substation measuring after uplifting to the transmission tension of 138kv. Another meter is in place at the “Tingo Maria” substation, which does not have any significance for the project activity
The Quantity of net electricity generation supplied by the project plant/unit to the grid in year y, will be calculated as the formula below:

$$EG_{facility,y} \quad (EG_{pj,y}) = \sum_h EG_{PJ,h}$$

The estimated location of the meters are as in the following chart.

[63] See: Technical Procedure of the Committee of Economic Operation of SINAC PR – 20 – Verification of Compliance with requirements for being a member of COES SINAC, p.20; in the internet: http://www.coes.org.pe/coes/Procedimientos/procedimiento_n20.pdf, web linked accessed on 09/11/2011



Data Collection and Integration: It is required that the Operator calculate the Project's ERs based on most recent available information, following the ERCP presented in this report. The Operator must gather and process information needed to monitor ERs. All data required for calculating the emission margin will come from the COES information system and the operator. Electricity production by the plant will be metered continuously to account for the net level of electricity sold to the grid, which itself will contain a record of the plant output, along with all other plants in the SEIN.

Data gathering and processing should be done by the Operator, as follows:

COES (Data Provider)	Report hourly generation of plants in the SEIN (measurement: 15'), available monthly. Report dispatch merit orders. As the project will be an active member of COES all data will come from COES. Use real NECs per power plant in the SEIN. Available once a year in the Annual Statistic of COES. This information will be monitored once for the crediting period.
Operator (Data processor)	Substantiate all ER claims with COES report data and /or final clients. Fill in monthly data in all required spreadsheets, following the ERCP Report hourly net generation of the Project in the SEIN (measurement: 15') and/or final clients, available monthly.

Procedures for review of reported results data and internal audits: quality control is established in the ERCP to ensure monitoring accuracy. Such procedures will include, but will not be limited to, the following:

- spreadsheets will be reviewed during yearly consolidation of monthly calculations;

- corrective actions will be taken in the case of malfunction or breakdowns, or simply for more accurate monitoring and reporting;
- an internal audit will be performed by the ERCP Steering Committee each monitoring period to see if the MP has been performed according the guidelines established in the PDD; and,

Independent verification of monitoring results and achievement of the ERs as calculated in the PDD is a critical outcome for all CDM projects. The ERCP Management should work closely with the DOE to assure a dependable and transparent outcome; and to that end, they will follow the procedures below for project performance reviews and corrective actions:

- keep efficient contact with the DOE who verifies the Project's ERs;
- provide all necessary monitoring information about the ERs to facilitate the verification work;
- during the crediting period, always take into account requests by the CDM Executive Board and conduct preparatory work for the Verification to obtain high quality results and efficiency;
- ensure review of the monitoring report by the ERCP Steering Committee before verification;
- cooperate to answer all questions raised by DOE during the Verification process; and
- archive all data for a period of 2 years from the end of the crediting period.

Upon detecting a problem or being informed of a discrepancy, ERCP Management will take immediate action to rectify it. Should COES fail to provide adequate information; the ERCP Steering Committee will file a claim with COES to obtain the information.[64] If a major investment is required, the ERCP Management will notify the ERCP Steering Committee to ask the management of Generación Andina S.A.C. to invest in the monitoring personnel or/and equipment.

B.Emissions Reductions Calculation Procedure and Required Spreadsheets

The ERCP is the basic instrument for gathering, recording and processing information that will result in the measured ERs. The Operator shall keep the ERCP as a reference manual. The ERCP should contain: (i) data gathered from COES, and (ii) data processed by the operator. All data processing should be done in Excel. The ERCP is designed for monthly calculation, based on final monthly COES reports. 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.

Calculation of Grid Emission Factors:
This Excel file contains all data and formulas necessary to calculate the Combined Emission Factor for the monitoring period.

[64] As a member of COES, the Project Developer has the right to seek get information from COES.

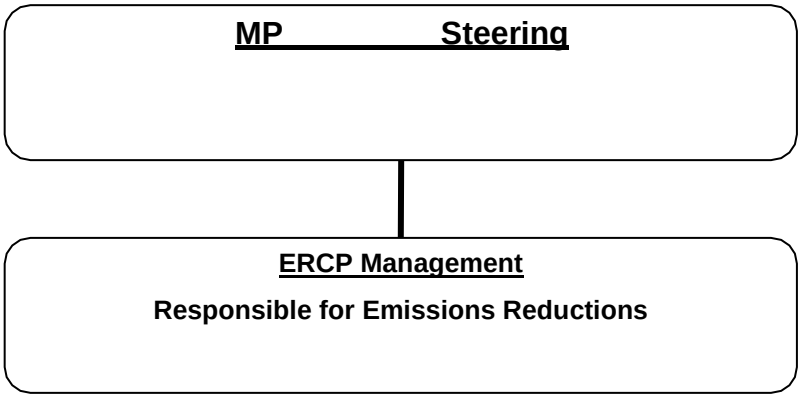
C. Other parameters

- **Cap $_{PJ}$:** The Installed capacity of the hydropower plant after the implementation of the project activity will measure as indicated on the manufacture´s nameplate. The monitoring frequency would be yearly and cross check with the annual statistic of COES available.
- **A_{pj}:** Area of the reservoir measured in the surface of the water, after the implementation of the project activity, when the reservoir is full. The built map of the reservoir was going to be used as a reference and once a year the area of the reservoir will be measured by an engineer. Monitoring frequency: yearly

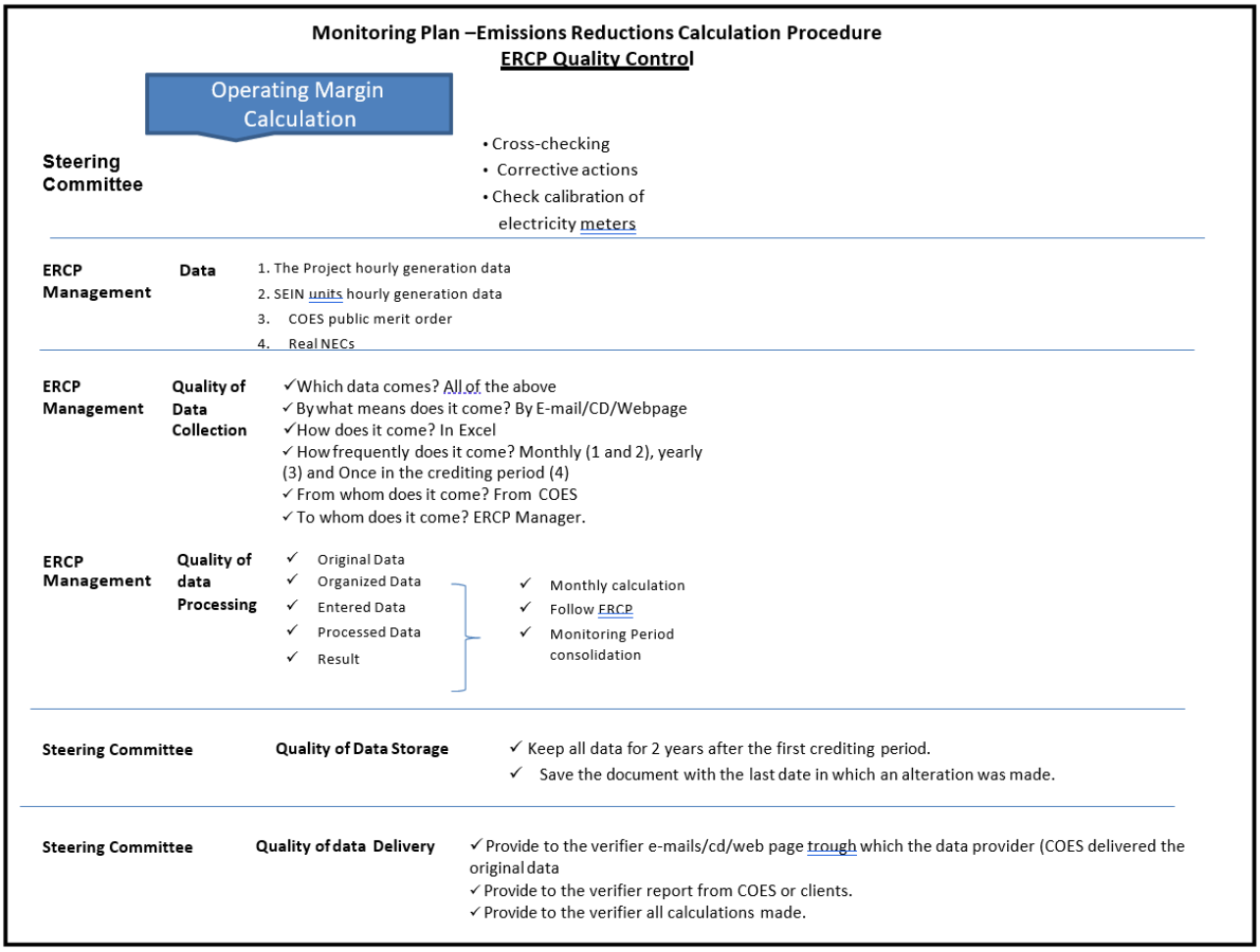
V. Annexes

The ERCP Organizational Structure and Quality Assurance and Control Procedure

ERCP Organizational Structure



Monitoring plan (MP) – Emissions Reductions Calculation Procedure (ERCP)



6. Summary report of comments received from local stakeholders

Please refer to Section 0 and 0

7. Summary of post-registration changes

The following revisions have been done in registered PDD and submitted for Post-Registration Changes according to Type of Changes:

Type of Change	Reason for change	Changes in PDD
Corrections	• As the CDM PDD template	• Editorial changes as per PDD

	changes from the time of preparation of registered PDD to the time of preparing the revised PDD for addressing Post-registration Changes. • As the project activity underwent some permanent changes during project implementation stage, these changes need to be addressed in Section A.1 in general description of the project as well as A.3.	Template version 11.0 • Info was added to the new sections A.6. and A.7, Appendix 6 and Appendix 7. • Revised general description of the project activity in Section A.1. and A.3. in order to justify the changes occurred during project implementation stage.
Change in Project Design	• Project design change has taken place through the change in technical specification for some cases viz. turbine capacity, generation capacity and turbine speed has changed and due to change in installed capacity, estimated net annual electricity generation has also changed – these changes need to be mentioned in PDD. • The change in project installed capacity has an impact on project financial indicators and these changes have to be mentioned in PDD. • The change in project installed capacity results in change in estimated net electricity generation and hence the estimated emission reductions calculation – these changes have to be presented in PDD	• Revised technical description in Section A1 and A.3. as per changes in the project design. The following changes have been implemented: Change of each generator nominal capacity to 12,930 kVA and a power factor of 0.9; the turbine capacity has been changed to 10,623 kW and the total installed capacity from 19.0 MW to 20.576 MW (combined generator capacity). Changes in net electricity generation due to a change in the total capacity let to a change in emission reductions. • Revised description of establishment of project additionality in Section B.5. in accordance with changes in financial indicators for the project. • Revision in Section B.6.3 and B.6.4 due to change in $EG_{PJ,y}$ and BE_y in accordance with the change in project design.

Change in Monitoring Plan	• As per the actual site-practice a different meter set-up has been chosen as compared to the registered PDD. The meter readings will be taken directly from meters at the power station and the joint meter reading problem as described in the registered PDD does no longer exist – these changes took place after the registration of the project activity with the CDM. In order to reflect these changes, the list of monitored parameters in Section B.7.1 of PDD are being revised (amended and reduced). • The Monitoring Plan in Appendix 5 was amended which had to be reflected in the PDD	• The new meters set up including a new line diagram was introduced to the monitoring plan • Exclusion of Monitoring Parameter $EG_{Nueva\ Esperanza,h}$, $EG_{EL\ Carmen,\ h}$ and $EG_{Tingo\ Maria,\ h}$ in Section B.7.1 in accordance with the change in monitoring plan. Amendments were applied to the "description" of parameter $EG_{8\ de\ Agosto,h}$ and to the "Measurement methods and procedures" $EG_{PJ,h}$. • Revision of parameter $EG_{PJ,h}$ in Section B.7.1 • • Appendix 5 was amended. The joint reading problem as described in the registered PDD does no longer exist. The calculation sheet will reflect

In accordance with CDM Project Standard Version 02.0 para 242, the impacts of the changes to the to the registered CDM project activity on the key project parameters have been explained below:

Criteria	Impact of the change in CDM project activity
The applicability and application of the applied methodologies, the applied standardized baselines and the other applied methodological regulatory documents with which the project activity has been registered;	The change in the CDM project activity (change in installed capacity from 19.0 MW to 20.576 MW) does not impact the applicability of the methodology – the installed capacity of the project after post registration change is 20.576 MW that is still above 15MW (the threshold of small-scale project activity) and the project activity supplies electricity (generated from renewable source) to grid – hence the methodology along with methodological regulatory documents is still applicable to this project.
The compliance of the monitoring plan with the applied methodologies, the applied	The change in the CDM project activity (project monitoring plan) does not impact the

standardized baselines and the other applied methodological regulatory documents	compliance of the monitoring plan with the applied methodologies, the applied standardized baselines and the other applied methodological regulatory documents - the monitoring methodology follows the ACM0002 definition, which states that “the monitoring shall consist of metering the electricity generated by the renewable energy technology.”, after change to the project activity, the monitoring still consist of metering the electricity generated by the renewable energy technology.
The level of accuracy and completeness in the monitoring of the project activity compared with the requirements contained in the registered monitoring plan	The change in the CDM project activity does enhance the level of accuracy and completeness in the monitoring of the project activity compared with the requirements contained in the registered monitoring plan – the change in the CDM project activity includes a moe specific measurement of the electricity calculation and is in accordance with the national regulation of the host country and manufacturer’s specification: Accordingly, the level of accuracy and completeness in the monitoring of the project activity is improved in the monitoring plan after change in the CDM project activity
The additionality of the project activity	Project IRR (without CER) of the CDM project after the change in project capacity (8.80%) is still well below the benchmark IRR (12.0%); in sensitivity analysis also, with the variation of +/- 10% of the selected parameters, project IRR remains below the benchmark in all cases. Besides, common practice analysis considering the increase in installed capacity also shows that the project is not a common practice. Considering these two points, it can be concluded that the change in CDM project does not impact the additionality of the project activity
The scale of the project activity	Project installed capacity after the change is 20.576 MW - hence the project falls in the category of large-scale project and it was a large scale before the change as well, so the

	change in project does not impact the scale of the project activity

In accordance with the requirements of §309 (b) of CDM VVS for Project Activities (version 02.0), the following is being clarified :

Point in time of changes

All changes have been designed after the registration of the project activity and before the physical implementation of the project.

Reasons for the implementation of changes

Prior to the actual construction of the hydro power plant the project owner of the project activity had changed several times. The initial project owner planned the installation of a set of three project activities with shared monitoring equipment (i.e. shared meters). This set-up let to a complex monitoring procedure as laid out in the former registered PDD. The implementing project owner has added meter equipment to make sure all power plants do have proper, calibrated exclusive meters at the sites. Furthermore, instead of three project activities, only two projects have been installed.

Could these changes have been known prior to the registration of the CDM project activity?

The registration of the project activities happened significantly before the actual implementation. Furthermore, as mentioned above, the project has been implemented by a different project owner. Therefore, the changes could not have been known prior to the registration of the project activity.

How do the changes impact the overall operation/ability of the CDM project activity to deliver emission reductions or net anthropogenic removals as stated in the PDD?

The project stays a run of river hydro power plant using the hydrology as used to the initial design of the project activity. The proposed changes do therefore not impact the ability of the project activity to deliver emission reductions.

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Document information

Version	*Date*	*Description*
11.0	31 May 2019	Revision to: • Ensure consistency with version 02.0 of the "CDM project standard for project activities" (CDM-EB93-A04-STAN); • Make editorial improvements.
10.1	28 June 2017	Revision to make editorial improvement.

Version	*Date*	*Description*
10.0	7 June 2017	Revision to: • Improve consistency with the “CDM project standard for project activities” and with the PoA-DD and CPA-DD forms; • Make editorial improvement.
09.0	24 May 2017	Revision to: • Ensure consistency with the “CDM project standard for project activities” (CDM-EB93-A04-STAN) (version 01.0); • Incorporate the “Project design document form for small-scale CDM project activities” (CDM-SSC-PDD-FORM); • Make editorial improvement.
08.0	22 July 2016	EB 90, Annex 1 Revision to include provisions related to automatically additional project activities.
07.0	15 April 2016	Revision to ensure consistency with the “Standard: Applicability of sectoral scopes” (CDM-EB88-A04-STAN) (version 01.0).
06.0	9 March 2015	Revision to: • Include provisions related to statement on erroneous inclusion of a CPA; • Include provisions related to delayed submission of a monitoring plan; • Provisions related to local stakeholder consultation; • Provisions related to the Host Party; • Make editorial improvement.
05.0	25 June 2014	Revision to: • Include the Attachment: Instructions for filling out the project design document form for CDM project activities (these instructions supersede the "Guidelines for completing the project design document form" (Version 01.0)); • Include provisions related to standardized baselines; • Add contact information on a responsible person(s)/ entity(ies) for the application of the methodology (ies) to the project activity in B.7.4 and Appendix 1; • Change the reference number from F-CDM-PDD to CDM-PDD-FORM; • Make editorial improvement.
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.

Version	*Date*	*Description*
04.0	13 March 2012	Revision required to ensure consistency with the "Guidelines for completing the project design document form for CDM project activities" (EB 66, Annex 8).
03.0	26 July 2006	EB 25, Annex 15
02.0	14 June 2004	EB 14, Annex 06b
01.0	03 August 2002	EB 05, Paragraph 12 Initial adoption.

Decision Class: Regulatory
Document Type: Form
Business Function: Registration
Keywords: project activities, project design document