Voluntary Carbon Standard
Project Description

Date of VCS PD: 10 November 2009
Version: 3

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1 Description of Project:

1.1 Project title

50 MW Sipansihaporas Hydro Power Plant, North Sumatra
Date: 10 November, 2009
Version: 3

1.2 Type/Category of the project

The project activity is a run-of river type hydro power plant in North Sumatra province in Indonesia. The total actual installed capacity of the project is 50 MW, comprised of a 33 MW and a 17 MW turbine, with a predicted electricity supply to the grid of 214,800 MWh per annum[1]. The project is owned and developed by PT. PLN (Persero), a state-owned electricity company in Indonesia. The project generates and supplies the electricity to the connected Sumatra grid. The electricity currently generated by the grid is relatively carbon intensive. The proposed project will increase the utilization of renewable energy sources, in this case hydro energy, by operating new hydropower plant.

According to the CDM UNFCCC criteria, one approved GHG program by the VCS Board, the project is classified as large scale and, based on Annex A of the Kyoto Protocol, falls under the following types/categories of the Clean Development Mechanism under Kyoto Protocol:

- "Consolidated baseline methodology for grid-connected electricity generation from renewable sources"

Reference: Approved consolidated baseline methodology ACM0002 version 10, sectoral scope 01 - Energy Industries (renewable-/non-renewable sources), effect as of EB 47

The specified project is not a part of a grouped project.

1.3 Estimated amount of emission reductions over the crediting period including project size:

The project activity is a run-off river type hydropower plant. Total installed capacity of the project is 50 MW, comprised of two turbines (a 33 MW turbine and a 17 MW turbine). The 50 MW installed capacity generates an average of 159,596 emission reduction credits per year.

Based on VCS Program Guidelines 2007.1, there are three project groups as follow:

- Micro projects: under 5,000 tCO_2-e per year
- Projects: 5,000 – 1,000,000 tCO_2-e per year
- Mega projects: greater than 1,000,000 tCO_2-e per year

The proposed project activity meets the requirement of the 'projects' group, which generates emission reduction credits between 5,000 – 1,000,000 tCO_2e per year.

Emission reduction estimates over a crediting period of ten years from 1 April 2006 until 31 March 2016 is provided in the table below:

Table 1 - Estimated amount of emission reductions from project activity

Years	Vintage year	Annual Agreed Volume*

[1] Feasibility Study page 14/19

2006 - 2007	1 April 2006 – 31 March 2007	159,596
2007 - 2008	1 April 2007 – 31 March 2008	159,596
2008 - 2009	1 April 2008 – 31 March 2009	159,596
2009 - 2010	1 April 2009 – 31 March 2010	159,596
2010 – 2011	1 April 2010 – 31 March 2011	159,596
2011 – 2012	1 April 2011 – 31 March 2012	159,596
2012 – 2013	1 April 2012 – 31 March 2013	159,596
2013 – 2014	1 April 2013 – 31 March 2014	159,596
2014 – 2015	1 April 2014 – 31 March 2015	159,596
2015 – 2016	1 April 2015 – 31 March 2016	159,596
Total estimated reductions (tCO_2e)		1,595,960
Total number of crediting years		10 years
Annual average of the estimated reductions over the crediting period (tCO_2e)		159’596

*The ER calculation is based on designed annual electricity generation stated in Sipansihaporas FS project report 1990.

1.4 A brief description of the project:

Indonesia has great potential for hydro energy resources that are not yet fully exploited. According to the national energy policy, the potential capacity of hydro resources in Indonesia is 75,000 MW of which only 3,200 MW has so far been used to generate electricity (including captive power and private entities)[2].

The project is a new run-off-river hydropower plant in North Sumatra Province in Indonesia. The project is owned and developed by PT. PLN (Persero), a state-owned electricity company.

The key purpose of the project is to utilize the hydrological resources of the Sibuluan River and another three lateral tributaries, thus a renewable source of energy generating zero emission electricity to be transmitted to the Sumatra grid (hereafter referred to as the grid) through the Sibolga PLN substations. The electricity currently generated by the grid is relatively carbon intensive It will displace fossil-fuel-based power plants and reduce the GHG emissions with fossil-fuel-based power plant in Sumatra grid. Therefore, the project activity is reducing greenhouse gas emissions.

The total installed capacity of the Project is 50 MW, comprised of a 33 MW and a 17 MW turbine, with annual energy generation of the project of 214,800 MWh, in which all of power generated will be delivered to the Sumatra grid. The electricity currently generated by the grid is relatively carbon intensive.

1.5 Project location including geographic and physical information allowing the unique identification and delineation of the specific extent of the project:

The project area of the Sipansihaporas Hydropower Plant is situated in North Sumatra Province at about 344 km south of Medan city as the capital city of North Sumatra province and 12 km east of Sibolga as the capital city of Tapanuli Tengah district. The principal structures of the Sipansihaporas project such as the main dam and waterway are situated in the downstream of the confluence of the three tributaries upstream of the Sipansihaporas River, which are Sarumanggita river, Natolbak river and Bargot river. The water flows from Sipansihaporas River with total catchment area of 196 km^2 for power station no. 1 and 210 km^2 for power station no. 2, with a yearly average flow of 28,5 m^3/sec. The exact location is 01° 44’ N and 98° 51’ E.

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[2] Indonesia Power Sector, EU-Indonesia Infrastructure Forum, November 2007. www.eurocham.or.id/download.php?path=EUROCHAM_UPLOAD_DIR&cid=217&id=185

The location of the project site is shown in the following maps:

Figure 1 - Location of Sipansihaporas Hydroelectric Power Plant

1.6 Duration of the project activity/crediting period:

As per the VCS policy announcement from the 10 September 2008, the project start date is the date on which the project activity began reducing or removing GHG emissions.

Following are the two units' commissioning date:
Unit 1: 14 December 2004 (commissioning certificate)
Unit 2: 21 October 2002 (commissioning certificate)

Thus, the project start date where project activity starts reducing emissions is 21 October 2002, as the earliest project start date of two units at Sipansihaporas Hydro Power Plant.

Crediting period start date: 01 April 2006.

Crediting period: 10 years fixed crediting period from 01 April 2006 until 31 March 2016.

1.7 Conditions prior to project initiation:

Not Applicable. This is a Greenfield project.

1.8 A description of how the project will achieve GHG emission reductions and/or removal enhancements:

The project utilizes a run-off-river for generating electricity which otherwise would have been generated through power plants connected to the Sumatra grid (mostly fossil-fuel-based power plants). Sumatra grid is operating with a mix hydro and fossil-fuel power plants.

The purpose of the project activity is to generate electricity using renewable hydro energy and sends it to the Sumatra grid. In the absence of the project activity, equivalent power would have been generated based on the fossil fuel intensive Sumatra grid resulting in Green House Gas emissions into the atmosphere.

1.9 Project technologies, products, services and the expected level of activity:

The project uses well-established hydropower generation technology for electricity generation and transmission, and is a run-of-river hydropower project with a total installed capacity of 50 MW (consisting of a 33 MW and a 17 MW turbine). Stringing another circuit of the existing 150 kV single circuit transmission lines, which is being operated in Sibolga substations, connects the project to the grid. The length of the new lines from each power station to the substation is 7.8 km and 0.9 km respectively.

The project consists of a main intake, tributary intakes, a waterway, a power station, hydro mechanical works, generating equipments, transmission line and substations, permanent roads, a base camp and an inflow monitoring system.

The intake structure was built downstream of the confluence of the three tributaries upstream of the Sipansihaporas River, which are Sarumanggita river, Natolbak river and Bargot river. It has a type of concrete gravity with the height of 38 m and the volume of 76,600 $m^{3.}$ This intake structure will control the water level in order to gain steady water flow. This will result in flooded area of less than 0.184 km^2 (an area of 0.184 km^2 will be used for any further calculations).

Following the intake structure will be the conveyance system. The conveyance system comprises two headrace tunnels and two penstocks, a pressure adjustment well and high pressure pipelines. The waterway has type of vertical shaft type. The water from the intake structure will flow through the headrace tunnel with a length of 1,502 m and penstock with a length of 272.2 m to the power station no. 1. The water discharged from the power station no.1 will flow through the headrace with a length of 2,843 m and the penstock with a length of 115.9 m to the power station no. 2. After power station no. 2 the water is discharged in to the Sibuluan River through a tailrace.

The headrace tunnel for power station no. 1 has a type of pressure tunnel and the headrace for power station no. 2 has a type of non-pressure tunnel. The penstocks have type of above ground. The power station is of a semi-underground type. The specific technical data of the turbines / generators are listed in Table 2 below:

Table 2 - Technical data of the turbine / generator units (specifications are per unit)

Turbines 1	Brand	MEIDEN
	Model	Francis vertical shaft
	Rated output	34,000 kW
	Rated head	128.4 m
	Rated speed	429 rpm
	Rated flow	28.5^3/s
	Serial number	M211071 CR1101

Generators 1	Brand	TOSHIBA
	Model	Francis vertical shaft
	Rated power	39,000 kVA
	Rated voltage	11 kV
	Rate current	2,047 A
	Rated frequency	50 Hertz
	Rated speed	429
	Rated factor	0.85

Turbines 2	Brand	MEIDEN
	Model	Francis vertical shaft
	Rated output	17,600 kW
	Rated head	67 m
	Rated speed	375 rpm
	Rated flow	28.5^3/s
	Serial number	M211071 CR2101

Generators 2	Brand	TOSHIBA
	Model	Francis vertical shaft
	Rated power	20,000 kVA
	Rated voltage	11 kV
	Rate current	1,050 A
	Rated frequency	50 Hertz
	Rated speed	375
	Rated factor	0.85

The electricity production can be described as follows: Water is taken from the intake structure, and then enters into the turbine through the high-pressure and non-pressure pipeline to produce electricity by driving the generators. In the end, the water will finally discharge into to the Sibuluan River through the tailrace.

The project uses well-established technology in electricity generation and transmission. The essential equipment used in the Project has to be procured from Japan, ensuring state of the art technology. Prior to project commissioning the project developer has organized a series of training together with the equipment supplier. The training conducted covered mainly the following topics: management of hydropower generation, operation and maintenance of hydro power plant, operation and maintenance of turbine, generator and other equipments. The purpose of the training is to enable the local staff to perform regular and safe operation and maintenance.

The main technical parameters of the proposed project are shown in table below:

Table 3 - Main technical parameters of the proposed project

Parameter	Capacity	Source
Installed capacity (MW) Unit 1 Unit 2	 33 17	Feasibility study page 14/19
Expected annual power generation (effective supply to the grid) (MWh) Unit 1 Unit 2	 142,200 72,600	Feasibility study page 14/19
Water head (m) Unit 1 Unit 2	 131.4 67.6	Feasibility study page 14/19
Design flow (m^3/s) unit 1 and unit 2	18.76	Feasibility study page 14/19
Capacity Factor (%)	49%	Calculated based on Feasibility study
Transmission loss (%)	1.00%	Feasibility study page 9-3

1.10 Compliance with relevant local laws and regulations related to the project:

The project meets all local laws and regulations by the government of Indonesia. The project activity, in using hydropower to generate electricity, is a voluntary action that has not been imposed by the government of Indonesia.

The project has a land deed agreement, construction permit and underwent an Environmental Impact Assessment (EIA).

1.11 Identification of risks that may substantially affect the project's GHG emission reductions or removal enhancements:

The hydropower plant is already commissioned and operating properly. Following are the risks that may substantially affect the project's GHG emissions reductions:

1. Supply of water
2. The project is a run-off-river hydropower plant and operation of the project really depends on the water supply. Supply of water also depends not only on the season but also influenced by the change in climate and the soil capacity to absorb the rainwater.

3. Natural disaster
   The project activity is located in a geologically sensitive region (ring of fire) where frequent natural disaster such as earthquake occurred. Also deforestation and high falling rain in the area will cause floods.

4. Unexpected machine breakdown.
   Even the project use proven technology, we have to consider unexpected machine breakdown.

1.12 Demonstration to confirm that the project was not implemented to create GHG emissions primarily for the purpose of its subsequent removal or destruction.

The hydropower project has been installed with the aim of harnessing the under-developed hydro potential of the region. The electricity generated from the project activity meets the power demand of the region. Hence, it is contributes greatly toward filling the gap of demand and supply in the

Sumatra region.

Thus, it is evident that project proponent has initiated this project with an aim to supply electricity to the grid, and not primarily for creating GHG emissions primarily for the purpose of its subsequent removal.

1.13 Demonstration that the project has not created another form of environmental credit (for example renewable energy certificates).

The project activity has not applied to any other form of environmental credits.

1.14 Project rejected under other GHG programs (if applicable):

Not Applicable.

1.15 Project proponents roles and responsibilities, including contact information of the project proponent, other project participants:

Table 4 - Details of project participants

Name of the party involved ((host) indicates a host party)	Private and/or public entity (ies) project participants (as applicable)	Responsabilities
Indonesia (host)	PT. PLN (Persero). (as public entity)	Project owner and operator
Switzerland	South Pole Carbon Asset Management Ltd. (as private entity)	Carbon credit buyer

Project proponents contact information as follows:

Project owner:

Organization:	PT. PLN (Persero)
Street/P.O.Box:	Jl. Trunojoyo blok M 1/135, Kebayoran Baru
Building:	
City:	Jakarta
State/Region:	
Postfix/ZIP:	12160
Country:	Indonesia
Telephone:	+62-21-725 1234
Fax:	+62 21 722 7026
E-Mail:	
URL:	www.pln.co.id
Represented by:	
Salutation:	Ms.
Last Name:	Semiawan
Middle Name:	
First Name:	Assistia
Mobile:	+62-811-962 833
Direct Fax:	+62 21 722 7026
Direct Tel:	+62-21 726 1122 ext. 1112
Personal E-Mail:	assistias@pln.co.id

Carbon credit buyer:

Organization:	South Pole Carbon Asset Management Ltd.
Street/P.O.Box:	Technoparkstrasse 1
Building:	
City:	Zurich
State/Region:	
Postfix/ZIP:	8005
Country:	Switzerland
Telephone:	+41-44 633 7870
Fax:	+41-44 633 1423
E-Mail:	info@southpolecarbon.com
URL:	www.southpolecarbon.com
Represented by:	
Salutation:	Mr.
Last Name:	Heuberger
Middle Name:	
First Name:	Renat
Mobile:	+41-79 549 3951
Direct Fax:	
Direct Tel:	
Personal E-Mail:	r.heuberger@southpolecarbon.com

1.16 Any information relevant for the eligibility of the project and quantification of emission reductions or removal enhancements, including legislative, technical, economic, sectoral, social, environmental, geographic, site-specific and temporal information.):

The project is contributing to sustainable development defined by the government of Indonesia specifically as follows:

Social well-being:

- The project contributes to the development of the region by increasing community development and corporate social responsibility of PT. PLN (Persero) such as infrastructure development (road, bridges); funds for building a new school, church and mosque in the region; upgrading health care facilities (a small clinic) as well as free medicines in the vicinity of the project for the benefit of the community.
- During both construction and operation, various kinds of mechanical work are required, providing employment on a regular and permanent basis.

Economic well-being:

- The project activity generates direct and indirect employment for skilled and unskilled manpower during construction phase as well as during operational stage and thus helped in controlling migration from the region and alleviation of poverty in the local area.
- The generated electricity is fed into regional grids through the local grid, thereby improving the availability of electricity to local consumers (villagers and sub-urban inhabitants) by increasing the electricity supply. Due to increased new opportunities for industries and economic activities arise with a chance for more local employment and better overall development.
- The project activity leads to diversification of the national energy supply that is dominated by conventional-fuel-based generating units.

- The project activity contributes to economic sustainability around the plant site and encourages economic power decentralization.

Environmental well-being:
- The project utilizes hydropower to generate electricity, which otherwise would have been generated through fuel- (most likely fossil-fuel-) based power plants. This way it is contributing to a reduction in specific emissions (emissions of pollutant/unit of energy generated), including GHG emissions.
- As hydroelectric power projects produce no end-products in the form of solid waste (ash, etc.), they don't have to cope with the problem of solid waste disposal encountered by most other sources of power.
- Being a renewable energy source, hydro energy is used to generate electricity that contributes to resource conservation.
- Thus, the project causes no negative impact on the surrounding environment; and in the end contributes to environmental well being due to the run-off river type of project activity.

Technological well being:
- The project supports high quality equipment transfer from other regions and even other countries, and contributes to capacity building of the labor force through training and practical work.
- The project promotes local products developed in the region, when replacement of spare parts is necessary, and supports renewable technology development especially for hydroelectric power technology.

In view of the above explanation, the project participants consider the project activity as profoundly contributing to sustainable development.

1.17 List of commercially sensitive information (if applicable):

All information provided in this project document and relevant supporting calculation sheets can be publicly published.

2 VCS Methodology:

2.1 Title and reference of the VCS methodology applied to the project activity and explanation of methodology choices:

The project primarily displaces power from the Sumatra grid. According to Annex A of the Kyoto Protocol, this project falls into Sectoral Scope 1 – Energy Industries (renewable-/non-renewable sources):

The approved consolidated baseline methodology ACM0002, "Consolidated baseline methodology for grid connected electricity generation from renewable sources", version 10, in effect as of EB 47.

This methodology also refers to the latest approved versions of the following tools:
1. The approved "Tool for demonstration and assessment of additionality", version 05.2.
2. The approved "Tool to calculate the emission factor for an electricity system", version 02.
3. The approved "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", version 02.

The project activity is not subject to any deviation or revision of the methodology. For more information regarding the proposals and their consideration by the Executive Board please refer to http://cdm.unfccc.int/methodologies/PAmethodologies/index.html.

2.2 Justification of the choice of the methodology and why it is applicable to the project activity:

Sipansihaporas hydroelectric power plant (HEPP) is a new grid-connected run-of-river type hydropower plant. According to "Section I: Source, Definitions and Applicability of Approved consolidated baseline and monitoring methodology ACM0002 Version 10", the project activity is applicable under the following conditions:

Applicability Condition	Project Compliance	Information Source
Project activity is a grid-connected renewable power generation project activity that (a) installs a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity (greenfield plant); (b) involves a capacity addition; (c) involves a retrofit of (an) existing plant(s); or (d) involves a replacement of (an) existing plant(s)	The project activity is a new hydropower plant (greenfield project). It is connected with a regional power grid, the Sumatra grid; the Sumatra grid is clearly identified and information on the characteristics of this grid is publicly available from PLN Sumatra[3].	PLN
The project activity is the installation, capacity addition, retrofit or replacement of a power plant/unit of one of the following types: hydropower 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.	The project activity is the installation of a new run of the river hydro power plant with an installed capacity of 50MW.	PLN
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.	The project activity is the installation of a new run of the river hydro power plant with an installed capacity of 50MW.	PLN
In case of hydro power plants, one of the following conditions must apply: • the project activity is implemented in an existing reservoir, with no change in the	- The project activity is constructed as a run-of-river hydropower project where there is no existing reservoir prior to	PLN

[3] PLN Sumatra is a regional state owned electricity company in Sumatra

Applicability Condition	Project Compliance	Information Source
volume of reservoir; or • the project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m2; or • the project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m^2.	the project activity (Greenfield project). - Not applicable. This is a Greenfield project. - The project activity is a run-off river hydropower plant. No reservoir exists in this sense but a regulating pondage can be seen as a reservoir. The power density of such is 281 W/m^2 (please see section 4.1 and 4.3)	
Project activities does not 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.	The project is a run-off-river hydropower plant and not a fuel switch project.	PLN
Project activity is not a biomass fired power plants.	The project is a run-off-river hydropower plant and not a biomass fire plant.	PLN
Hydro power plants that result in new reservoirs or in the increase in existing reservoirs where the power density of the power plant is less than 4 W/m^2.	Not applicable. The project activity is a run-off river hydropower plant. No reservoir exists in this sense but a regulating pondage can be seen as a reservoir. The power density of such is 281 W/m^2 (please see section 4.1 and 4.3)	PLN

The applicability criteria stated in methodology ACM0002 (Version 10) are met on the basis of the reasons above.

2.3 Identifying GHG sources, sinks and reservoirs for the baseline scenario and for the project:

Table 5 - Summary of Gases and Sources included in project boundary

	Source	Gas	Included ?	Justification / Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity.	CO_2	Yes	Main emission source. CO_2 emissions from grid electricity production.
		CH_4	No	Minor emission source
		N_2O	No	Minor emission source
A	For hydro power	CO_2	No	Minor emission source

	plants, emissions of CH_4 from the reservoir	CH_4	No	Not applicable since the project is a run-of-river hydropower plant with a daily regulating pond for temporary storage.
		N_2O	No	Minor emission source

2.4 Description of how the baseline scenario is identified and description of the identified baseline scenario:

As per the approved consolidated methodology ACM0002, version 10, since the project activity involves the installation of a new grid-connected hydro power plant, the baseline scenario is the following:

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 (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

The project activity uses the "BASELINE METHODOLOGY PROCEDURE" as described in the applied methodology.

Identification of the baseline scenario

As per the methodology, if 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 (CM) calculations described in the "Tool to calculate the emission factor for an electricity system".

Since the project activity is the installation of a new grid-connected hydroelectric power plant hence the baseline scenario is the same as described above. Combined margin (CM) for the grid has been calculated as per "Tool to calculate the emission factor for an electricity system".

2.5 Description of how the emissions of GHG by source in baseline scenario are reduced below those that would have occurred in the absence of the project activity (assessment and demonstration of additionality):

As per ACM002 version 10, the additionality of the project activity shall be demonstrated and assessed using the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the CDM Executive Board.

The following steps are used to demonstrate the additionality of the project according to the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the Executive Board (version 05.2, EB 39).

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

The baseline is defined for a Greenfield project as per methodology as '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 (CM) calculations described in the "Tool to calculate the emission factor for an electricity system"'. Therefore according to the Validation and Verification manual, no further analysis is required.

Step 2. Investment Analysis

Sub-step 2a: Determine appropriate analysis method
According to the "Tool for the demonstration and assessment of additionality (version 05.2)", three options can be applied to conduct the investment analysis. These are the simple cost analysis (Option I), the investment comparison analysis (Option II) and the benchmark analysis (Option III).

Since this project will generate financial/economic benefits other than VCS-related income, through the sale of generated electricity, Option I (Simple Cost Analysis) is not applicable.

Since there are no other alternatives considered of designing the project activity. Hence, option II the investment comparison analysis is not relevant and not applicable.

According to the Additionality Tool, either Option II or Option III can be chosen in the context of the project activity. Given that the baseline is the continuation of supply of electricity from the grid and not an alternative power plant with similar output, benchmark analysis (Option III) is then used for assessing the financial attractiveness of the project activity most accurately.

Sub-step 2b: Option III – Application of benchmark analysis
The likelihood of the development and further operation of this project, as opposed to the continuation of the purchase of grid electricity from the current electricity generation mix (i.e. its baseline) will be determined by comparing the project IRR (without carbon benefits) with benchmark rates available to a local investor. These could be provided by local banks, or investment bonds in the host country or it could be internally calculated based on accepted models such as below. Method used for calculating the benchmark is WACC (weighted average cost of capital) whereas cost of each type of capital financing the project is either given or calculated. Then these costs are averaged. The benchmark incorporates also lending rate as part of WACC calculation. WACC calculation is chosen as the appropriate benchmark since the Capital employed in financing the project consists of loan and Government's equity. Basically, the project needed loan from foreign institution not only to complement the government's equity to finance the project, to reduce the investment risk, and to increase the economic attractiveness of the project.

Table 6 - Parameter used for the Weighted Average Cost of Capital WACC calculation

Parameters	Value	Description	Source
Risk free rate	6.31%	30-year US Treasury Bill, value of beginning year 1996.	US Department of the Treasury[4]
Beta	0.83	Average beta for electricity generation, distribution, and transmission, integrated in 2003 – 2008; according to Prof. Damodaran.	Prof. Aswath Damodaran[5]
Premium risk	13.33%	Using Equity Country	Prof. Aswath Damodaran.

[4] http://www.ustreas.gov/offices/domestic-finance/debt-management/interest-rate/yield_historical_main.shtml

[5] Dr. Aswath Damodaran is a Professor of Finance at the Stern School of Business at New York University. He is best known as author of several widely used academic and practitioner texts on valuation, corporate finance, and investment management. http://pages.stern.nyu.edu/~adamodar/

(1993 - 1996)		premium risk by utilizing the data 2000 to 2005. From this data, the premium risk of period 92 to 96 is calculated using the Fisher model.	Interest parity is used to find the equivalent equity country risk premium year 92 to 96, based on inflation[6].
Cost of debt	2.6% in JPY[7] 9.66% in IDR eq.	Actual interest lending rate which has been converted from JPY loan interest rate to IDR loan interest equivalent	% in JPY based on Sipansihaporas loan letters (which is significantly lower the interest rate stated in feasibility study); % in IDR is calculated using Fisher model of interest rate parity (see below for explanation)
Cost of Equity	17.37%	Calculated using CAPM (see below)	Valuation book by Damodaran[8] and McKinsey & Company Ltd.
Tax	30%	Income tax for calculating the WACC and also used in the cash flow	Tax regulation UU. no. 17 year 2000[9]
Debt Amount	385,510,044,000 IDR eq.	Investment part which is debt	USD denomination debt based on Feasibility study[10] IDR equivalent: calculated using Foreign Currency Investment Disbursement 1992-2005 and IDR/USD Exchange Rate in 1992-2005
Equity Amount	229,553,544,000 IDR eq.	Investment part (equity from government fund).	USD denomination equity based on Feasibility study IDR equivalent: calculated using Foreign Currency Investment Disbursement 1992-2005 and IDR/USD Exchange Rate in 1992-2005[11]
IDR/USD Exchange Rate	2,344.82	IDR/USD Exchange Rate in 1996	International Trade Administration USA[11]
IDR/JPY	21.42	IDR/JPY Exchange Rate	Oanda.com[12]

[6] *Global Finance*. Maximo V.Eng, Francis A. Less, Laurence J. Mauer. HarperCollins College Publisher. 1995. Page 106-113.

[7] Loan letter IP443, IP463

[8] Damodaran on Valuation by Aswath Damodaran page 20-42 published by Wiley Frontiers in Finance

[9] www.pajak.go.id, *Undang-undang nomor 17, tahun 2000*

[10] Feasibility study page 9-6

[11] http://ia.ita.doc.gov/exchange/index.html

[11] http://ia.ita.doc.gov/exchange/index.html

Exchange Rate		in 1996	

Model for calculating benchmark

The applied benchmark is determined by using the WACC model since the capital financing of the project is a mix of both equity and debt. Based on information submitted by PLN (feasibility study and other sources), the project cost in USD currency is financed by a loan from the foreign bank with an interest rate of 2.6% in JPY denomination. The feasibility study mentions USD denominated loan with an expected interest rate of 10%. Due to conservativeness the actual loan interest rate has been used for the calculation of cost of debt. Debt/equity ratio of the project activity is 1.71 times. Equity financing is supported by the government of Indonesia in form of an APBN (*Anggaran Pendapatan dan Belanja Negara*) or government's budget. In order to be able to compute the WACC, the cost of debt, the burden of equity or investors' expected return in equity, and the cost of debt should be calculated first.

1. *Calculate IDR equivalent cost of debt using Interest Rate Parity (Fisher model) and Purchasing Power Parity model*

Since the revenues of the project activity are based on IDR and loan investments are in JPY, the project is exposed to currency risk towards JPY denomination by carrying JPY financing. When an obligation is denominated in a foreign currency, in this case JPY currency, the loan interest rate in JPY term will be inappropriate when directly inserted to the above WACC formula, due to the foreign exchange exposure inherent in the financing. The foreign exchange exposure comprises as follows:

1. The revenue generated is in IDR currency and the obligation to pay the debt is in JPY currency. If IDR is depreciated against JPY, it will have a direct impact on PLN's ability in servicing its debt[13]. Such an impact is accounted for by applying the fisher model, elaborated below.
2. The project's location, Indonesia, implies additional risks such as political, economic, business risk (supply and demand risk) and the risk of natural disasters, etc. Such adverse circumstances have an impact on local currency pricing and thus possibly affecting revenue as they often correlate directly to inflation and currency figures[14]. Such an impact is accounted for by applying the fisher model, elaborated below.

Thus, for comparison, the JPY Loan interest rate should be first converted into an IDR interest rate equivalent by utilizing the interest rate parity model by Fisher[15] as shown below. The loan interest rate differential obtained shall be representing the currency risk exposed that is included in determining the benchmark indicator or the reserve margin (hedging) against IDR/JPY currency exchange rate to which the project's expected IRR should at least cover. Usually, the all-in

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[12] http://www.oanda.com/convert/fxhistory

[13] *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-263.

[14] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19-21.

[15] *Global Finance*. Maximo V.Eng, Francis A. Less, Laurence J. Mauer. HarperCollins College Publisher. 1995. Page 106-113; and *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-264.

lending rate in foreign currency will be close to the cost of borrowing in domestic markets due to the interest rate parity relationship[16].

$$S_{t+1} = S_t \times \frac{1+\inf_{IDR}}{1+\inf_{JPY}} \qquad \text{Fisher 1)}$$

$$S_{t+1} = S_t \times \frac{1+CD_{IDR}}{1+CD_{JPY}} \qquad \text{Fisher 2)}$$

$$\hat{S} = \hat{P}_{JPY} - \hat{P}_{IDR} \qquad \text{Fisher 3)}$$

Parameters	Description	Value	Base
S_t	IDR/JPY Spot Rate	21.42	JPY/IDR exchange rate in 1996
S_{t+1}	1-year IDR/JPY Future Spot Rate	22.90	Calculated
$\inf_{IDR}$	IDR inflation rate	6.996%	IDR Inflation Rate in 1996[17]
Inf_{JPY}	JPY inflation rate	0.099%	JPY inflation rate in 1996
CD_{JPY}	JPY cost of debt	2.6%	Loan interest and capital payment disbursement
CD_{IDR}	IDR equivalent cost of debt	Calculated	
S	Percent change in JPY or other foreign currency price to IDR		
P_{JPY}	Percent change in price level in Japan or other foreign currency		
P_{IDR}	Percent change in price level in Indonesia		

The model explains how spot exchange rates tend to adjust to differences in inflation. It defines the equilibrium between present and future spot rates and differences in interest rates between two countries. The exchange rate adjustment will be equal and opposite to the interest rate differential. The spot rate must change to offset differential rates of inflation in the two countries compared. There are 2 steps to determine the IDR equivalent for the JPY cost of debt:

a. First step: Determine the 1-year IDR/JPY Future Spot Rate in 1997 based on 1996 IDR/JPY spot rate
   Using formula Fisher 1) and the data below, the 1-year IDR/JPY Future Spot Rate results in 22.90

Parameters	Value	Base
S_{t+1}	22.90	Calculated
S_t	21.42	IDR/JPY exchange rate in 1996, when the project was initiated and loan was disbursed
$\inf_{IDR}$	6.996%	IDR Inflation Rate in 1996
Inf_{JPY}	0.099%	JPY inflation rate in 1996

b. Second step: Determine the IDR-equivalent cost of debt

[16] *Valuation: Measuring and Managing The Value of Companies.* Copeland, Tom; Koller, Tim; Murrin, Jack; McKinsey & Company. 2nd edition. 1994. page 262-264.

[17] International Monetary Fund, 2008 World Economic Outlook, http://www.indexmundi.com/indonesia/inflation_rate_(consumer_prices).html

Using the formula of Fisher 2) and the data below, the IDR equivalent cost of debt results in 9.66%. Compared to the actual 16.36% domestic investment credit rate in 1996[18], the calculated IDR equivalent cost of debt is found to be conservatively lower at 9.66%.

Parameters	Value	Base
Cd_{IDR}	9.66%	Calculated
Cd_{JPY}	2.60%	Loan interest from PLN's annual report
S_{t+1}	22.90	Calculated from Fisher 1)
S_t	21.42	IDR/JPY exchange rate in 1996

2. *Calculate cost of equity using Capital Asset Pricing Model (CAPM)*

To calculate the Cost of Equity, there are two models to be explained below:

First Model:

CAPM = Capital Asset Pricing Model
*CAPM = Domestic Risk Free Rate + beta * (Domestic market return – Domestic Risk Free Rate)*

CAPM measures risk in terms of non-diversifiable variance and relates returns to the specified risk measure. It produces the minimum expected rate of return on equity investment for the particular project. The risk premium used in the CAPM is generally based upon historical data, and the premium is defined to be the difference between average returns on stocks and average returns on risk free securities in a mature equity market over the measurement period.

William Sharpe (1964) published the capital asset pricing model (CAPM). Treynor (1961) and Lintner (1965) also performed parallel work. CAPM extended Harry Markowitz's portfolio theory to introduce the notions of systematic and specific risk. For his work on CAPM, Sharpe shared the 1990 Nobel Prize in Economics with Harry Markowitz and Merton Miller.

This model is the most common model applied in capital market practice. It utilizes the domestic market return to find the additional risk premium over the risk free rate when investing equity in projects. In 1996, the Indonesian capital market was immature and in a state of development thus information for market return in 1996 is unattainable. Therefore, this model is not possible to be applied in this project activity.

Second Model:

*Expected Cost of Equity = Risk free Rate + beta *(Equity Market Risk + Country Risk)*[19]

Above model is issued by Prof Aswath Damodaran.

This second model is applying the US risk free rate and the US market return as the normal basis return that investors around the world would expect when investing in a particular country. To cover the currency exposure when investing in countries other than the US, the model applies country risk premium as rate adjustment.

Parameter	**Value**	**Source**

[18] http://books.google.com/books?id=fTbRlHrA3igC&pg=PA253&lpg=PA253&dq=Bank+Indonesia+selected+rate+1986+-+1997&source=bl&ots=CGttCt2wIt&sig=OtiTDkZ0dl_Nl5MS65su2ppKwHo&hl=en&ei=sUX5SoqYFIeQ6AP0gsmXCg&sa=X&oi=book_result&ct=result&resnum=4&ved=0CBUQ6AEwAw#v=onepage&q=Bank%20Indonesia%20selected%20rate%201986%20-%201997&f=false.

[19] Prof. Aswath Damodaran http://pages.stern.nyu.edu/~adamodar/pdfiles/papers/riskprem.pdf

Risk free rate	6.31%	30-year US Treasury Bill, value at average in 1996.
Beta	0.83	Average beta for electricity generation, distribution, and transmission, integrated in 2003 – 2008; according to Prof. Damodaran.
Equity market risk + country risk	13.33%	Total risk premium Indonesia average 1992 – 1996, calculated using Interest Rate Parity Fisher model based on inflation during the period 1992-1996 and 2000 – 2005 and total risk premium Indonesia during the period 2000-2005. See calculation below.
Expected Cost of Equity	17.37%	Calculated. Cost for investing in Equity

The risk free rate used in this model is using US risk free rate as US financial market and capital market are assumed to be the most mature financial market in the world. Since the country risk for 1996 is unavailable, the number is then calculated by following model Risk premium is calculated using the Fisher model. The risk premium for 1996 is taken as the average risk premium between 1992 and 1996. In comparison, average inflation data in Indonesia in 1992 to 1996 and 2000 to 2005 are used. Below is the equation to calculate the average risk premium during the period 1992 to 1996 using the Fisher model 1):

$$\frac{1+ECR_{92-96}}{1+ECR_{00-05}} = \frac{1+\inf_{92-96}}{1+\inf_{00-05}}$$

Parameters	Description	Value	Source
ECR_{92-96}	Average Total premium risk (US market risk + country risk in 1992 – 1996)	13.33%	Calculated
ECR_{00-05}	Average Total premium risk premium in 2000 – 2005	13.29%	Prof. Aswath Damodaran
Inf_{92-96}	IDR average inflation rate in 1992 – 1996	8.43%	International Monetary Fund, 2008 World Economic Outlook
Inf_{00-05}	IDR average inflation rate in 2000 – 2005	8.39%	International Monetary Fund, 2008 World Economic Outlook

Hence the minimum cost of equity for the project is expected to be 17.37%, in order to categorize the project as financially attractive for an equity investor.

The data to produce the cost of equity utilizes the information from the year 2000 to 2005, being defined as economic normal condition. Such condition definition is determined based on the average actual inflation during the period. The average is then compared with the inflation average during the years 1992 to 1996. If the average differential between two periods is insubstantial, the condition could be defined as similar. After comparison, the interest rate parity model (see below section) is then applied to figure out the equivalent total risk premium for Indonesia during period 1992 to 1996. The risk premium equivalent results in 13.33% for year 1992 to 1996.

3. *Calculate WACC* (Weighted Average Cost of Capital) as benchmark IRR

$$WACC = \frac{CD \times Debt \times (1 - Tax) + CE \times Equity}{Debt + Equity}$$

Parameters	Description	Value	Source
WACC	Weighted average cost of capital	10.72%	Calculated
Cd_{IDR}	IDR equivalent cost of debt	9.66%	Calculated
Debt	Amount of debt	385,510,044,000 IDR	See table 6
Tax	Taxation value	30%	See table 6
CE	Cost of equity	17.37%	See table 6
Equity	Amount of equity	229,553,554,000 IDR	See table 6

WACC, is defined as the weighted average of the costs of the different components of financing used by the firm. With a cost of equity of 17.37% and an IDR-equivalent cost of debt of 9.66%, the **WACC is found to be 10.72%**. While the project IRR is 3.78%, the project return is significantly below the benchmark indicator.

Lending to PLN comprises of some considerably high investment risks. Besides the pre-mentioned risks in building the project, the firm's unstable balance sheet raises concern and a potential risk that needs to be considered when determining the appropriate benchmark indicator. Based on the Impact Evaluation Study report by ADB, PLN's financial performance – was unsatisfactory throughout the 1980s mainly due to low operating efficiency, inadequate tariffs, and a high share of socially oriented events. PLN turned profitable in 1990. The government of Indonesia was reluctant to substantially increase the electricity tariff rate to achieve the target of the financial covenant stipulated in the loan agreement. Hence, the debt-service coverage ratio, of not less than 1.5 times, was complied with in most years except 1987 and 1988. The stipulated self-financing ratio of not less than 30% of capital expenditure was complied with only in 1995 and 2001, and the covenanted 8% of return on net fixed assets was never achieved.

On the whole, while the efforts of ADB and the World Bank attempted to enable PLN to achieve the stipulated financial targets through the use of covenants and policy, dialogue with the government was unsuccessful. It is a logical consequence that ADB did not provide any new project loans to the Indonesian power sector between 1996 and 2001, partly because of the government's reluctance to approve tariffs to an adequate level to cover costs of supply. Following the onset of the Asian financial crisis, the Indonesian Rupiah depreciated more than fourfold before stabilizing again. This had an immediate adverse impact on PLN's profitability given that more than 70% of its expenses and all PPAs (power purchase agreement between PLN and Independent Power Producer who built power plant and sell electricity to PLN) were dollar-denominated. Tariff levels in real terms began to deteriorate in 1994 and were improved after 2000 following the introduction of quarterly increases that were intended to enable PLN to achieve its covenanted rate of return. Due to the severe Asian financial crisis in addition to other financial factors, PLN was unable to repay the loan in time. Field investigations and surveys reported that there was ample evidence of a reduction in the quality of PLN's services as its financial health deteriorated after the financial crisis[20],

In PLN's 2002 annual report it is was stated that "The financial condition of PLN was classified as unhealthy due to an operational loss that reached IDR 8,162 Billion. Although the Basic Electricity Rate for 2002 had already been approved, the average sale price that reached IDR 448.03/kWh was still below the cost for production or below its economic value". Within the period of 1999 to 2000, the annual reports display PLN's poor financial performance. Earning of

[20] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19-21.

fixed assets were mostly negative due to loss of operating profit during low profit period. This also leads to a negative rentability ratio (profit per total asset average) and return on investment ratio for most of the periods. Liquidity ratios were predominantly below, showing the inability of the company to perform standby liquidity in the event that the loans mature. Debt to equity ratios for most of the periods are about 3 to 4 times, especially within the year of 1999 where PLN experienced a significant loss from its operation. But in 2002, the report has shown a sharp escalation of equity due to the asset re-evaluation as opposed to profit creation[21].

In conclusion, it can be summarized that:
During the period of submitting loan proposal to ADB/World bank/other G to G financier, PLN had expected and construct tariff proposal which aimed to comply with the various financial ratios stipulated under the loans of ADB/World Bank/other G to G financier. Unfortunately, the tariff target as proposed was never materialized, from period of 1991 to 2000, the tariff was never brought up by more than 5% due to the Government's reluctance to approve tariffs adequate to cover costs of supply VCS will be meaningful to compensate of somewhat missing revenue which had been aimed based on an increased electricity tariff.

PLN's operational performance in the early 1980s was generally unsatisfactory, characterized by low system load factors, excessive losses, and low sales per consumer and per employee. One of the factors was an unfavourable consumption structure and load demand profile, which limited the leverage available to PLN to draw profitable revenues from industrial consumers (Over 70% of PLN's total consumers were small residential and commercial consumers using electricity primarily for lighting only)[22].

In conclusion, it could be summarized that:
1. PLN did not meet its financial ratios stipulated in the loan covenant, especially due to the government's reluctance to adequately increase the tariff in order to meet target covenanted ratios,
2. The asian and domestic financial crisis, during 1998 and 1999, had a severe influence in the deterioration of PLN's balance sheet despite subsequent improvement,
3. VCS revenue would help to achieve a more sound financial position. VCS revenue would assist PLN in meeting all the stipulated financial targets in the ADB loan covenant,
4. VCS revenue would help to develop the surrounding water catchment area by means of reforestation.

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Sub-step 2c: Calculation and comparison of financial indicators
The table below shows the financial analysis for the project activity without carbon finance. As shown, the project's IRR without carbon (3.78%) is lower than the benchmark rate of return applicable (10.72%), calculated with shown formula above and supported by other investment risks elaborated and explained above. The VERs are important to alleviate the infeasible IRR and help the project become more attractive.

Calculation of the IRR and NPV is based on the annual cash flow, which considers the annual revenue of produced electricity, yearly operating cost, and investment cost.
Items to be considered in cash flow:

- Revenue
- Operating cost and maintenance
- Tax
- Depreciation (to calculate tax, but it will be added back, thus it doesn't affect the cash flow)

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[21] PLN Annual Report year 2002.

[22] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19, paragraph 56, 57, page 43 (for tariff) and page 17-18 par 53

Cash flow is calculated as follows:

Revenue – operating expenses

= Earnings before interest, taxes and depreciation (EBITDA) – depreciation and amortization
= Earnings before interest and taxes (EBIT) – taxes
= Net income + depreciation and amortization
= Cash flows from operations – capital expenditures – working capital needs
= Free cash flow[23]

Cash flow is computed in IDR denomination currency since:
1. The project is located in Indonesia; the appropriate associated risks are Indonesian country risks and market risks as it is utilized in the WACC calculation. All risks, such as natural disaster risk, political stability risk, economy risk, currency risk, etc. have a particular likelihood in Indonesia and would have a direct impact on the survival of the project; ergo, presenting cash flow in the domestic currency is more appropriate,
2. The revenue is in Indonesian currency,
3. Operating and Maintenance cost is dominated in IDR.

Table 7 - Summary of project financial analysis (without carbon finance)

Parameter	Without VCS
IRR	3.78%
Applicable Benchmark	10.72%

The parameters presented in the table 8 have been used to conduct the financial analysis.

Table 8 - Economic parameters used in the project

Name	Value	Source
Installed capacity (MW)	50	Feasibility study page
Output Capacity (kWh/year)	214,800,000	Feasibility study page
Income tax (%)	30%	Government policy[24]
Project cashflow (Year)	30	Hydro sector
Tariff for PLN, excluding VAT (IDR/MWh)	155.87	Feasibility study 1990 page 163. Calculated based on tariff of Rp. 117.68 in 1986 and escalated by 2.85% as an average tariff of 1990 – 1994 in order to achieve an appropriate value for 1996
Total investment (IDR)	615,063,588,000	Feasibility study
Operating costs (IDR/MWh)	9,225,954,000	Feasibility study

Sub-step 2d: Sensitivity analysis

A sensitivity analysis has been performed to determine in which scenarios the project activity would overtake the benchmark, indicating its viability. The project viability is evaluated through the increment + or - 10% of the following parameters: (1) electricity tariff; (2) electricity generation); (3) total investment, (4) operational cost.

[23] Damodaran on Valuation by Aswath Damodaran page 20-42 published by Wiley Frontiers in Finance.

[24] Indonesian Government (1994), Perubahan Atas UU no. 7/1983 tentang Pajak Penghasilan sebagaimana telah diubah dengan UU no. 7/1981 (*Revision of Government Law no. 7/1983 about Income Tax, as has been revised by Government Law no 7/1981*), [Online] Undang-Undang no 10/1994 (*Government Law no. 10//1994*), in effect since 1 January 1995, Available from: http://www.pajak.go.id/peraturan/view_doc?docid=16andsearchterm16&searchterm=None.

Table 9 summarizes the results of the sensitivity analysis.

Table 9 - Different parameters affecting the project's IRR

Scenario	% change	IRR (%)
Original		3.78%
Increase in Tariff	10%	4.53%
Increase in Electricity Generation	10%	4.53%
Reduction in Investment Costs	10%	4.38%
Reduction in Operational Costs	10%	4.01%

These results show a reasonable range of fluctuation by the four parameters, the IRR of the proposed project is still lower than the benchmark, which obviously demonstrates that the proposed project will reach financial attractiveness varying crucial parameters within a realistic range.

As a comparison the same four parameters have been adjusted in Table 10 until the benchmark is hit to elaborate the robustness of the IRR calculation.

Table 10 - Different parameters to hit the benchmark

Scenario	% change	IRR (%)
Original		3.78%
Increase in Tariff	121%	10.72%
Increase in Electricity Generation	121%	10.72%
Reduction in Investment Costs	62%	10.72%
Reduction in Operational Costs	100%	5.82%

The revenue is based on the electricity tariff and production that are both unlikely to increase significantly. A strong increase of the electricity tariff is unlikely as the government is reluctant to increase the electricity costs for the consumer.

Tariff and PLF:

These results show that the IRR will hit the benchmark by increasing project revenue by 121%, These variations are unlikely to occur, given the past circumstances and the fact that the government of Indonesia was reluctant to increase the tariff. The electricity tariff is unlikely to increase more than 10% (based on the actual data on average selling price from 1990 to 2001, 2002,2003)[25] since the tariff components increase in accordance with the countries inflation.

Investment cost:

[25] Asian Development Bank report July 2003, *Impact evaluation study of Asian Development Bank Assistance to the power sector in Indonesia*, page 19-21 and www.pln.co.id

On the other hand, an investment reduction is also unlikely to occur, since the construction has started and the material prices are increasing as inflation is applied each year in Indonesia. So, a 62% reduction in the investment will not be possible. Even if the project had not started, a 62% reduction in investment cost would be an unlikely event.

Operation cost:

Even if operation and maintenance cost were set to zero, the calculated project IRR would still be under the benchmark.

In conclusion and overall this project is not financially attractive.

Step 4. Common Practice Analysis

Indonesia has an abundant amount of hydro resources that have not been fully utilized. According to publicly accessible governmental information, the potential capacity of hydro resources in Indonesia is 75,000 MW of which only 3,200 MW has so far been used to generate electricity (including captive power and private entities). Thus, hydroelectric generation cannot be considered to be common practice (detailed explanation is given in Step 4.a and 4.b of the Common Practice Analysis below):

Sub-step 4a: Analyze other activities similar to the proposed activity
The development of hydropower projects greatly relies on the hydrological resources available. The common practice analysis is limited to northern Sumatra grid level, since in 1997, at investment decision date, Sumatra still consisted of two different grids; northern Sumatra grid and southern Sumatra grid. These grids were not yet interconnected. They have been interconnected in year 2007. To compare projects from different grid would therefore lead to unrepresentative results.

According to 1997 data of an all installed power plant in northern Sumatra grid, no other large-scale hydropower plant that was built in the region. The characteristics of all power plants are described in Table 11. Across the whole part of northern Sumatra, only 0.58% of the total installed capacity of the power plants is generated through hydro power plants. In terms of energy productin, the hydro power plants account for 7,500 KW in installed capacity out of 1,284,940 KW of installed capacity

Table 11 - Existing hydropower plants in the region

Name of Power Plant	Install Capacity (kW)	Location	Operating Year
GT-21 BELAWAN*	130,000	Sumbagut	1995
ST-10 BELAWAN*	149,000	Sumbagut	1995
GT-22 BELAWAN	130,000	Sumbagut	1994
ST-20 BELAWAN	162,580	Sumbagut	1994
PLTM-1 BATANG GADIS	450	Sumbagut	1994
PLTM-2 BATANG GADIS	450	Sumbagut	1994
GT-11 BELAWAN	117,500	Sumbagut	1993
PLTU-3 BELAWAN	65,000	Sumbagut	1989
PLTU-4 BELAWAN	65,000	Sumbagut	1989
PLTM-1 BOHO	200	Sumbagut	1989
PLTM-1 AEK RAISAN	750	Sumbagut	1989
GT-12 BELAWAN	128,800	Sumbagut	1988
PLTM-2 KOMBIH	750	Sumbagut	1988
PLTM-2 TONDUHAN	200	Sumbagut	1988

PLTM-4 KOMBIH	750	Sumbagut	1988
PLTM-1 AEK SILANG	750	Sumbagut	1988
PLTM-1 TONDUHAN	200	Sumbagut	1987
PLTM-1 KOMBIH	750	Sumbagut	1987
PLTM-3 KOMBIH	750	Sumbagut	1987
PLTM-2 AEK RAISAN	750	Sumbagut	1987
PLTM-1 AEK SIBUNDONG	750	Sumbagut	1987
PLTD-4 GUNUNG SITOLI	1,220	Sumbagut	1987
PLTD-6 GUNUNG SITOLI	1,220	Sumbagut	1987
PLTD-1 GUNUNG SITOLI	560	Sumbagut	1986
PLTD-2 GUNUNG SITOLI	560	Sumbagut	1986
PLTD-6 LUENG BATA	6,370	Sumbagut	1986
PLTD-7 LUENG BATA	6,370	Sumbagut	1986
PLTD-8 LUENG BATA	6,370	Sumbagut	1986
PLTD-9 LUENG BATA	6,370	Sumbagut	1986
PLTD-10 LUENG BATA	6,370	Sumbagut	1986
PLTD-5 LUENG BATA	3,280	Sumbagut	1985
PLTU-1 BELAWAN	65,000	Sumbagut	1984
PLTU-2 BELAWAN	65,000	Sumbagut	1984
PLTD-4 LUENG BATA	2,300	Sumbagut	1984
PLTG-5 PAYA PASIR	21,350	Sumbagut	1983
PLTD-3 LUENG BATA	4,040	Sumbagut	1981
PLTD-4 TELUK DALAM	530	Sumbagut	1980
PLTD-5 TELUK DALAM	530	Sumbagut	1980
PLTD-2 TELUK DALAM	750	Sumbagut	1978
PLTD-3 TELUK DALAM	250	Sumbagut	1978
PLTD-7 GUNUNG SITOLI	530	Sumbagut	1978
PLTD-8 GUNUNG SITOLI	530	Sumbagut	1978
PLTD-1 LUENG BATA	1,000	Sumbagut	1978
PLTD-2 LUENG BATA	1,000	Sumbagut	1978
PLTG-3 PAYA PASIR	20,100	Sumbagut	1978
PLTG-4 PAYA PASIR	20,100	Sumbagut	1978
PLTD-6 TELUK DALAM	750	Sumbagut	1976
PLTD-1 TITI KUNING	4,140	Sumbagut	1976
PLTD-2 TITI KUNING	4,140	Sumbagut	1976
PLTD-3 TITI KUNING	4,140	Sumbagut	1976
PLTD-4 TITI KUNING	4,140	Sumbagut	1976
PLTD-5 TITI KUNING	4,140	Sumbagut	1976
PLTD-6 TITI KUNING	4,140	Sumbagut	1976
PLTG-1 PAYA PASIR	14,470	Sumbagut	1976
PLTG-2 PAYA PASIR	14,470	Sumbagut	1976
PLTD-3 GUNUNG SITOLI	340	Sumbagut	1976
PLTD-5 GUNUNG SITOLI	340	Sumbagut	1976
PLTG-1 GLUGUR	19,850	Sumbagut	1975
PLTG-2 GLUGUR	12,800	Sumbagut	1967

Total install capacity of all power plants (kW)	:	1,284,940
Total install capacity of hydropower plants (kW)	:	7,500
Percentage of Hydropower plant	:	0.58%

As shown in the table above, the project activity is the only a large-scale hydropower plant in the region that is connected to the grid. The other hydropower plants are mini hydro power plant.

The installed capacity of existing hydroelectric plants with large capacity in the northern Sumatra grid is very limited compared to other generation sources. Therefore, the development of this type of project activity is not considered to be common practice.

Sub-step 4b: Discuss any similar options that are occurring
The project is located in northern Sumatra region. Table 10 in sub-step 4a shows all hydropower plants developed in the Northern Sumatra region. The majority of projects listed above are developed by PLN as a state-owned company in Indonesia and connected to the grid. There is another a large-scale hydropower plant called Asahan hydropower plant which was developed by INALUM as a private power production company, supplying all electricity generated to their own aluminum smelter plant, not connected to the grid.

According to the Decree of the Ministry of Environment No. 17/2001, all hydroelectric power plants with a dam height of ≥ 15 meters, or flooded area of ≥ 200 ha, or installed capacity of ≥ 50 MW need to undertake an Environmental Impact Assessment (EIA). Projects with an installed capacity of less than 50MW were thus excluded from the analysis in accordance with the guidance on common practice in the additionality tool: "If necessary data/information of some similar projects are not accessible for PPs to conduct this analysis, such projects can be excluded from this analysis". Two projects fit into this category of which one them is the underlying project activity.

Investigating these two large-scale hydropower plants, with installed capacity above 50 MW, shows that there are essential distinctions between the Asahan hydropower projects and the proposed project. The project activity is the only large-scale run-off-river hydropower plant in the region that is connected to the northern Sumatra grid. Asahan hydropower plant is a reservoir hydropower plant owned by private company and not connected to the grid. Asahan hydro is a joint venture between the government of Indonesia and a consortium of 12 Japan companies with little trouble financing such a large project. On the other hand, all PLN large-scale hydro projects need financing or loan from other institutions.

As stated above, it is concluded that the proposed project is not common practice in the region.

In conclusion the proposed project is deemed to be additional according to ACM0002.

3 Monitoring:

3.1 Title and reference of the VCS methodology (which includes the monitoring requirements) applied to the project activity and explanation of methodology choices:

The project uses the CDM-board-approved monitoring methodology ACM0002, "Consolidated monitoring methodology for zero-emissions grid-connected electricity generation from renewable sources", version 10, 11 June 2009.

The approved methodology of ACM0002 is chosen and applicable to the proposed project due to the following reasons:

- The project activity is the installation of an accumulation run-off-river hydroelectric power plant.
- The proposed project is not an activity that involves switching from fossil fuels to renewable energy at the site of the project activity.

- The project activity is not a biomass-fired plant.
- It is connected with a regional power grid, the Sumatra grid; the Sumatra grid is clearly identified and information on the characteristics of this grid is publicly available from PLN Sumatra[26].
- There is no reservoir for this project therefore the power density of the project is more than $10W/m^2$.

Based on stated reasons above, the applicability criteria of the approved CDM methodology ACM0002 (version 10) are met.

3.2 Monitoring, including estimation, modelling, measurement or calculation approaches:

- *Purpose of monitoring*
  To present reliable and complete data and to ensure that all actual project data is well organized in terms of collection and archiving.

- *Types of data and information to be reported, including units of measurement*
  Net electricity generated in kWh
  Electricity imported from the Sumatra grid in kWh
  Amount of diesel fuel used in metric tonnes or litres

- *Origin of the data*
  Net electricity generated (Electricity Transfer Protocol Report in monthly basis)
  Electricity imported from the Sumatra grid (Electricity Transfer Protocol Report in monthly basis)
  Diesel fuel quantity (calculated from diesel genset operational data in logbook)

- *Monitoring, including estimation, modelling, measurement or calculation approaches*
  No estimation, modelling or measurement approach needs to be applied for accomplishing the monitoring report. All necessary monitoring data can be collected directly and used for the calculation of the emission reductions. Calculation of the emission reduction will be done as described in section 4 of this document.

- *Monitoring times and periods, considering the needs of intended users*
  Monitoring of diesel used will be monitored monthly, electricity generation, own consumption, export and import will be monitored continuously and summarized daily, monthly or quarterly with regular yearly reports dependent on the monitoring plan for each data parameter for the entire crediting period.

- *Monitoring roles and responsibilities*
  Project proponent has assigned a team responsible for collecting all monitoring data and information.

- *Managing data quality*
  Project proponent implements QA/QC procedures to ensure data quality. All meters and equipments measuring data will be calibrated on regular basis (generally yearly basis as defined in detail in section 3.3 of this document).

3.3 Data and parameters monitored / Selecting relevant GHG sources, sinks and reservoirs for monitoring or estimating GHG emissions and removals:

[26] PLN Sumatra is a regional state owned electricity company in Sumatra.

Data and parameters to be monitored

Data/Parameter:	$EG_{PJ,y}$
Data unit:	kWh
Description:	Net Electricity supplied to the grid by the project activity during the year y
Source of data to be used:	kWh meter at project activity site (switchyard) The electricity generation's data used for monitoring is the monthly electricity generation report delivered to grid signed by both parties of generation department and transmission department (Joint Meter Reading).
Value of data applied for the purpose of calculating expected emission reduction:	214,800,000
Description of measurement methods and procedures to be applied:	Electricity produced will be measured by a watt-hour meter (connected to a digital control system and recorded continuously), which can measure export and import electricity data separately. Net electricity delivered to the grid would be the difference of electricity generation and own consumption. The Electricity Transfer Protocol Report form will be the basis for calculation of the emission reductions. The joint meter reading taken at the transaction point is witnessed by the presence of P3B officials as transmission department and the PP representative as generation department. The measurement of electricity generation will be conducted on a continuous basis, where monthly data is recorded and continuous total electricity measurement will be available. The measurement results will be summarised in regular production reports. The accuracy class of main and back up meter is 0.2
QA/QC procedures to be applied:	The QA/QC will be conducted through cross-checking with sales electricity receipts. Meters will be calibrated on yearly basis according to the national standard or other documents. Data measured by meters will be cross-checked by electricity sales receipts. The meter (s) will either: i) be read frequently and jointly by the generation unit and transmission unit, ii) be read by the project proponent (generation unit) and the data will then be double checked with the electricity sales receipts using comparison meter, iii) only be read by the grid company (transmission department). Monitoring Frequency: Monitoring is continuous with monthly recording of data.
Any comment:	

Data/Parameter:	$FC_{i,y}$
Data unit:	litre
Description:	Amount of diesel fuel used in the hydropower plant operation during the year y
Source of data to be used:	Measured - Project Owner-diesel fuel operational logbook
Value of data applied for the purpose of calculating expected emission reduction:	108 The data above is the highest data based on actual data recorded by project.

Description of measurement methods and procedures to be applied:	Fuel consumption will be recorded monthly, specifically for each fuel (currently only diesel consumption is available). Fuel consumption will be calculated from static graduated level gauges on the fuel injection tanks by using emergency diesel genset, resulted in litres then converted to tonnes using fuel specific density or scientifically proven fuel densities.
QA/QC procedures to be applied:	-
Any comment:	Fuel consumption will only occur in emergencies when power plant is not operational and the grid is also not available, a confluence of events which is expected to happen very rarely; at other times the plant will run on grid electricity. Emergency diesel genset is only for critical instrument/control system during turbine trip and shutdown.

Data and parameters to be available during validation for project emission calculation:

Data/Parameter:	$EF_{grid,CM,y}$
Data unit:	tCO_2/MWh
Description:	Grid Emission Factor of Sumatra
Source of data to be used:	DNA of Indonesia http://dna-cdm.menlh.go.id/id/database/DNA CDM_Grid_Sumatera_JAMALI_2008
Value of data applied for the purpose of calculating expected emission reduction:	0.743
Description of measurement methods and procedures to be applied:	No measurement required. Data is obtained based on analysis of DNA published information following the "Tool to calculate the emission factor for an electricity system" (EB 35 Annex 12).
QA/QC procedures to be applied:	-

Data/Parameter:	$NCV_{i,y}$
Data unit:	GJ/kg
Description:	Net calorific value of diesel fuel
Source of data to be used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied for the purpose of calculating expected emission reduction:	0.043
Description of measurement methods and procedures to be applied:	-
QA/QC procedures to be applied:	-
Any comment:	-

Data/Parameter:	Pi

Data unit:	kg/m^3
Description:	Density of diesel fuel
Source of data to be used:	Pertamina diesel fuel specification[27]
Value of data applied for the purpose of calculating expected emission reduction:	0.815 kg/liter = 815 kg/m^3
Description of measurement methods and procedures to be applied:	-
QA/QC procedures to be applied:	-
Any comment:	-

Data/Parameter:	$EF_{CO2,i,y}$
Data unit:	tCO_2/GJ
Description:	Weighted average CO_2 emission factor of diesel fuel in year ‘y’
Source of data to be used:	2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data applied for the purpose of calculating expected emission reduction:	0.074
Description of measurement methods and procedures to be applied:	-
QA/QC procedures to be applied:	-
Any comment:	-

3.4 Description of the monitoring plan

This section details the steps taken to monitor on a regular basis the GHG emissions reductions from the project activity according to ACM0002 version 10.

The monitoring plan for this project has been developed to ensure that the project collects and archives complete data from the very start.

1. Monitoring organization

The monitoring team has been established and integrated within the existing organization structure of the Sipansihaporas hydropower plant prior to the start of the verification. Clear roles and responsibilities is assigned to all staff involved in the VCS project and the prospect of nominating a VCS manager have been considered. The VCS manager has the overall responsibility for the monitoring system on this project.

All other VCS monitoring staff will have clearly defined roles and responsibilities. The VCS manager will manage the process of training new staff; ensure trained staff performs the

[27] Pertamina Solar Characteristic

monitoring duties as necessary; and ensure that where trained monitoring staff is absent, the integrity of the monitoring system is maintained by other trained staff.

A formal set of monitoring procedures is established prior to the start of the verification. These procedures will detail the organization, control, and the steps required for certain key monitoring system features, including:

a) VCS staff training
b) VCS data and record keeping arrangements
c) Data collection
d) VCS data quality control and quality assurance
e) Equipment maintenance
f) Equipment calibration
g) Equipment failure

The procedures will be agreed and signed off by PT PLN (Persero) and South Pole Carbon Asset Management Ltd. Any changes to procedures will need to be agreed by both parties. The VCS manager will be responsible for ensuring that the procedures are followed on site and for continuously improving the procedures to ensure a reliable monitoring system is established.

2. Monitoring equipment and installation

Considering that the emission factor is calculated *ex-ante* and according to the monitoring methodology ACM0002, the only data to be monitored is electricity export to the grid and electricity import from the grid by the project (detailed in section 3.3).

Metering of Electricity Supplied to the Grid
The main electricity meter for establishing the electricity delivered to the grid (detailed in section 3.3) is installed at the Sipansihaporas power plant. This electricity meter will be the main meter (revenue meter), measuring the quantity of electricity supplied to the grid that will be paid by the PLN. Net electricity delivered to the grid would be the difference of electricity generation and own consumption (electricity generation minus own consumption). As this meter provides the main VCS measurement, it will be the key part of the verification process. The meter is located at the Sipansihaporas power station.

The project developer owns the meter and is responsible for its maintenance and calibration, as stated in the SOPs agreed upon with the PLN. PLN and its representative are entitled to be present during any test, inspection, maintenance, and replacement of any part of the metering system, which will be performed by the meter manufacturer on request of the project developer.

To ensure maximum data availability and to introduce data quality controls, two cross-check meters are installed in addition to the revenue meter. Those meters are located at the Sipansihaporas power station, measuring electricity production from the project and own consumption.

Electricity meters should meet the relevant local standards at the time of installation and will be calibrated by the manufacturer before installation. The meters will be installed by the project according to the Indonesian standard “Standard Electricity Meter Equipment”. Records of the meter (type, make, model, and calibration documentation) will be retained in the quality control system on-site.

All equipment will be calibrated by the manufacturer according to relevant local standards at the time of installation and maintained in accordance with the manufacturer’s recommendations to ensure accuracy of measurements. Records of the meter (type, make, model, calibration, and maintenance documentation) will be retained as part of the VCS monitoring system.

Quality Control
The main meter is owned by the project and installed at the Sipansihaporas power plant. The project specifies the QC procedure for measurement and calibration to ensure the measurement accuracy of the main meter. Periodic checks should be conducted according to the relevant national standard[28]. In the event of any broken security seal in the metering system; or when the system fails to register; or if the measurement result is found upon testing to vary more than the allowable error from the standard meter used in the test, then an adjustment shall be made correcting all measurements of energy made by the metering system, as described in the SOP.

In case of failure of the main meter, production meter and own consumption meter which also located at generation site will be used as the cross-check meter, measuring the quantity of electricity exported from the project. The difference between electricity produced and consumed on-site shall be valid for claiming carbon credits. In the special case of total failure of all meters no credits will be claimed during such period.

During monthly monitoring of electricity delivered, the main meter and check-meters will be read and if the difference between the respective main meter and check-meters exceeds the maximum error for such meters then all meters shall be tested in turn. The main meter shall be used as transfer data and provide a letter of agreement.

During testing, if all meters are found to be working beyond the permissible limits of error, then the electricity delivered for the previous billing month shall be corrected to account for this error. The meters shall be calibrated and data will be calculated manually. However, manually calculated electricity production will not be used to claim carbon credits.

During annual calibrations, if the main meter is found to be within the permissible limits of errors, and the check-meters are found to be beyond the permissible limits of errors, the main meter shall be used for electricity delivered.

In case, during the annual tests, the main meter is found to be beyond the permissible limit of error but check-meters are found to be within the permissible limit of error, then check-meters reading shall be used for electricity delivered.

In case, during annual tests, both, the main meter and the check-meters are found to be beyond the permissible limit of error, then the meters shall be replaced with spare set of calibrated meters.

The electricity delivered for this period (from the date of last calibration) shall be corrected for the maximum error in meters.

3. Data recording procedure

The procedures for collecting the electricity meter data will be outlined in the Standard Operating Procedure signed between the project owner and the Grid Operator (both are under PLN).

All relevant data will be archived electronically and backed up regularly. Uncertainty will be considered to achieve conservative results. Moreover, it will be kept for the full crediting period, plus two years after the end of the crediting period or the last issuance of VCUs for this project activity (whichever occurs later). The Monitoring Plan has been developed to ensure that the project has robust data collection, processing, and archiving procedures.

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[28] Indonesian Government (1981) *Metrologi Legal*, [Online], Government Law no. 02/1981, in effect since 1 April 1981, Available from: http://www.unmiset.org/legal/IndonesianLaw/uu/Uu198102.htm.

Other data for VER procedures will be managed by the dedicated VCS Manager.

EG recording procedure and Monthly Electricity Protocol Report (Berita Acara):

- Operating and maintenance supervisor (O&M supervisor) responsible for recording the amount of electricity generating imported and exported by generating unit as the result from kWh meter downloading,
- Operating and maintenance supervisor responsible for constructing the electricity generating protocol report, which includes calculation of net electricity, delivered to PLN transmission unit. This report has to be reported and signed by unit manager, which will then be further reported to the sector manager. VCS manager will have the copy of such report and be notified as well,
- O&M supervisor with other authorized staff from generating unit will attract the data by downloading via computer from the kWh electronic meter and then record it in the form of Monthly Electricity Protocol (MEP) which shall be signed by both generating unit (PLN Sipansihaporas generating department) and PT. PLN (transmission department). The joint meter reading taken at the transaction point is witnessed by the presence of P3B officials as transmission department and the PP representative as generation department.
- The MEP will be then rechecked by authorized person from transmission unit for Pandan sector.

After all such information is rechecked and agreed by all related parties, the MEP will be signed by all authorized parties from generating unit and transmission unit. The report will thus be sent to PLN Medan as headquarter for all power plant units in northern Sumatra.

Main meter failure – use of cross-check meter data
If the main electricity meter is found to be faulty during its reading, data from the production and own consumption meter will be used in its place. In this circumstance, the electricity exported to the grid should be calculated as follows:

a) The data from the production and own consumption meter will be used for the period of the main meter failure. As all meters are situated after the transformer, no losses occur.
b) The electricity used and measured for own consumption should be deducted from the produced electricity measured. The difference will be equal to the net electricity produced.

Cross-check meter failure
A failing cross-check meter will be repaired or replaced by an accredited equipment testing organization appointed by PLN. Maintenance records and any calibration documents will be retained by the project and ensured by the operation and maintenance supervisor that the calibration documents comply with calibration requirements. In case of a cross-check meter failure simultaneously to a main meter failure no electricity produced can be measured and therefore no credits can be claimed.

Possible fault with either meter
During the process of cross checking the electricity data from the two meters, a difference may be established that is considerably larger than the historic difference (allowing for transmission losses). In this unlikely case, either electricity meter could be at fault. The data recording procedures for this circumstance will be specified in a separate procedure.

4. Data and records management

At the end of each month the monitoring data needs to be filed electronically. The electronic files need to have CD back-up and/or printout. The project developer needs to keep electricity sale and purchase invoices. All written documentation such as maps, drawings, the EIA and the feasibility study, are being stored for the crediting period and two years afterwards, and be made available to the verifier so that the reliability of the information may be checked.

In order to make it easy for the verifier to retrieve the documentation and information in relation to the project emission reduction verification, the project developer should provide a document register. The document management system will be developed to ensure adequate document control for VCS purposes.

The dedicated VCS Manager of the project developer is responsible for checking the data (according to a formal procedure) and the VCS Manager will be responsible for managing the collection, storage and archive of all data and records. A procedure will be developed to manage the VCS record keeping arrangements. All the data shall be kept until two years after the end of credit period.

4 GHG Emission Reductions:

4.1 Explanation of methodological choice:

According to the latest version of ACM0002 version 10, the procedure of determining baseline emission, project emission, leakage, and emission reduction for the project activity are as follows:

Baseline Emission

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

$$BE_y = EG_{PJ,y} * EF_{grid,CM,y} \qquad (1)$$

Where:

BE_y	=	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 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* (ton CO_2 /MWh)

Calculation of $EG_{PJ,y}$

For Greenfield renewable energy power plants:

$$EG_{PJ,y} = EG_{facility,y} \qquad (2)$$

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

Calculation of $EF_{grid,CM,y}$ of Sumatera grid

The Grid Emission Factor used in the calculation is calculated as a combined margin (CM), consisting of the combination of Operating Margin (OM) and Build Margin (BM) according to the procedures prescribed in the "Tool to calculate the emission factor for an electricity system", Version 01.1, 29 July 2008 (EB 35, Annex 12).

According to the tool, following steps are applied:

Step 1. Identify the relevant electric power system
Step 2. Select an operating margin (OM) method
Step 3. Calculate the operating margin emission factor according to the selected method
Step 4. Identify the cohort power units to be included in the build margin (BM)
Step 5. Calculate the build margin emission factor
Step 6. Calculate the combined margin (CM) emission factor

Step 1. Identify the relevant electric power system

According to the latest version of the tool, the Sumatra power grid is selected as the project boundary, as the regional interconnected grid covering all provinces in Sumatra Island. The project is located in North Sumatra province, and is connected to the existing Sumatra power transmission line. The Sumatra power grid is therefore determined as the project boundary. Both the OM and the BM will be calculated ex-ante.

Step 2. Select an operating margin (OM) method

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

(a) Simple OM, or
(b) Simple adjusted OM, or
(c) Dispatch data analysis OM, or
(d) Average OM.

In order to apply the simple OM method the low-cost/must run ration of the grid shall be below 50%. The grid connected to the project activity had ratios of 20.95%, 17.28%, 19.52%, 21.99% in the years 2003 to 2007, which are all below the 50% threshold. The calculation of such has been further elaborated in the Indonesian DNA approved emission factor calculation.

Step 3. Calculate the operating margin emission factor according to the selected method

The Operating Margin will be calculated ex-ante, therefore the factor is calculated based on three (3) recent years available data.

$$EF_{OM,simple,y} = \frac{\sum_{i,m} FC_{i,j,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{\sum_{m} EG_{j,y}} \qquad (3)$$

Where:

$EF_{OMsimple,y}$	=	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$FC_{1,y}$	=	Amount of fossil fuel type I consumed in the project electricity system in year y (mass or volume unit)
$NCV_{i,y}$	=	Net caloric value (energy content) of fossil fuel I in year y (GJ / mass or volume unit)

$EF_{CO2,I,y}$	=	CO_2 emission factor of fossil fuel type I in year y (tCO_2/GJ)
EG_y	=	Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants / units, in year y (MWh)
i	=	All fossil fuel types combusted in power sources in the project activity system in year y
y	=	Either the three most recent years for which data is available at the time of submission of the CDM-PDD to the DOE for validation (ex-ante option) or the applicable year during monitoring _ex-post option), following the guidance on data vintage in step 2

Step 4. Identify the cohort power units to be included in the build margin (BM)

The Project Developer can choose to use following options to calculate Build Margin Emission Factor ($EF_{BM,y}$), which is based on a sample group m that consists of either one of the following; whichever comprises the larger annual generation:

a. five power plants that have been built most recently, or
b. power plant capacity additions that comprises 20% of the system generation that have been built most recently

In terms of vintage of data, the project participant can choose one of the following options:

Option 1
"For the first crediting period, calculate the build margin emissions factor ex-ante based on the most recent information available on units already built for sample group m at the time of VCS-PD 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 emission factor during the crediting period."

Option 2
"For the first crediting period, the build margin emission factor shall be updated annually, ex-post, including those units built up to the year of registration of the project activity or, if information up to the year of registration is not yet available, including those units built up to the latest year for which information is available. For the second crediting period, the build margin emission factor shall be calculated ex-ante, as described in Option 1 above. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used."

Based on calculation, the set of power units describe as (b) in Sumatra grid comprises the larger annual generation than that of (a), the sample group (b) should be used for calculating the build margin of Sumatra grid. Option 1 is applied to calculate the build margin.

Step 5. Calculate the build margin emission factor

Once the sample group 'm' is defined, the build margin is calculated ex-ante using the following equation:

$$EF_{grid,BM,y} = \frac{\sum_{m} EG_{m,y} \times EF_{EL,m,y}}{\sum_{m} EG_{m,y}} \quad (4)$$

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 power generation data is available

Step 6. Calculate the combined margin (CM) emission factor

The combined margin emissions factor is calculated as follows:

$$EF_{grid,CM,y} = EF_{grid,OM,y} \times w_{OM} + EF_{grid,BM,y} \times w_{BM} \quad (5)$$

Where:

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

Project Emission

For most renewable power generation project activities, $PE_y = 0$. However, some project activities may involve project emissions that can be significant. These emissions shall be accounted for as project emissions by using the following equation:

$$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y} \quad (6)$$

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)

The project activity is a run-off-river type hydropower project. According to the methodology (for hydropower project activities that result in new reservoirs and for hydropower project activities that result in the increase of existing reservoirs), project proponents shall account for CH_4 and CO_2 emissions from the reservoir. If the power density of the project activity *(PD)* is greater than 10 W/m^2, the $PE_{HP,y}$ could be neglected or zero *(0)*.

The power density of the project activity needs to be considered using the following equation:

$$PD = \frac{Cap_{PJ} - Cap_{BL}}{A_{PJ} - A_{BL}} \quad (7)$$

Where:

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

Project emissions could occur by the backup diesel generator and got taken into account. The function of the backup diesel generator is to supply emergency power to start the turbines and generators when the power plant is accidentally fully stopped and the electricity supply from the connected grid is failed. It will be operating only a few hours per year.

The records on diesel consumption are made on a daily basis in the genset operation logbook. This has been included in the project emission calculation from the project activity. The basis for calculation is the values of density of diesel and emission factor for diesel.

Project emissions from diesel fuel consumption, $PE_{FF,y}$, during the entire crediting period are calculated as follows, whereby $PE_{FF,y} = PE_{FC,j,CO2}$:

"Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion" (version 02)

$$PE_{FC,j,CO2} = \Sigma FC_{i,j,y} \times COEF_{i,y} \quad (8)$$

Where:

Parameter	Description	Unit	Value	Source
$PE_{FC,j,CO2}$	CO_2 emissions from fossil fuel combustion in process j during year y	tCO_2/y	Calculated	Equation 8
$FC_{i,j,y}$	Quantity of fuel type i combusted in process j during the year y	litre/y	Measured	Sipansihaporas HEPP
$COEF_{i,y}$	CO_2 emission coefficient of fossil fuel type i in year y	tCO_2/litre	3.1863	Equation 9
i	Fuel types combusted in process j during year y	-	i= Diesel oil	Sipansihaporas HEPP

$COEF_{i,y}$ is calculated using option B. Option B calculates $COEF_{i,y}$ based on net calorific value and CO_2 emission factors of fuel type i, as follows:

$$COEF_{i,y} = NCV_{i,y} \times EF_{CO2,i} \quad (9)$$

Where:

Parameter	Description	Unit	Value	Source
COEF	CO_2 emission coefficient of	tCO_2/litre	3.1863	Equation 9

$COEF_{i,y}$	CO_2 emission coefficient of fossil fuel type i in year y	tCO_2/litre	3.1863	Equation 9
$NCV_{i,y}$	Weighted average net calorific value of fuel type i in year	TJ/t	0.043	IPCC 2006 default for diesel oil and density of diesel oil
$EF_{CO2,i}$	Weighted average CO2 emission factor of fuel type i in year y	tCO_2/TJ	74.1	IPCC 2006 default for diesel oil
i	Fuel types combusted in	-	i= Diesel oil	Sipansihaporas

Leakage

According to the methodology, leakage from related emission sources do not need to be considered, thus leakage is zero.

$$L_y = 0$$

Emission Reductions

Emission reductions are calculated as follows:

$$ER_y = BE_y - PE_y - LE_y \quad (10)$$

Where:

ER_y	=	Emission reduction in year *y* (t CO_2e/yr)
BE_y	=	Baseline emissions in year *y* (t CO_2e/yr)
PE_y	=	Project emissions in year *y* (t CO_2e/yr)
LE_y	=	Leakage emissions in year *y* (t CO_2e/yr)

4.2 Quantifying GHG emissions and/or removals for the baseline scenario:

According to the latest version of ACM0002 version 10, the procedure of determining baseline emission, project emission, leakage, and emission reduction for the project activity are as follows:

Baseline emissions

$$BE_y = EG \cdot EF_{grid,CM,y} \quad (11)$$

Parameter	Description	Unit	Value	Source
BE_y	Baseline emissions in year *y*	tCO2/yr	159,596	Calculated equation 11
$EG_{PJ,y}$	Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the project activity in year y	MWh/yr	214,800	Planned electricity production as per feasibility study
$EF_{grid,CM,y}$	Combined margin CO_2 emission	ton CO_2	0.743	See

Calculation of $EF_{grid,CM,y}$

As per newest “Tool to calculate the emission factor for an electricity system” for each crediting period the most recent data available at time of submission of the PD to the DOE for validation shall be used. The latest available data at the time is the official emission factor published by the Indonesian DNA using data from the year 2008 concluding an emission factor of 0.743 tCO_2e/MWh.

Summary of Baseline Emissions (BE_y)

Years	Vintage	BE_y (tCO_2e)
2006 - 2007	1 September 2006 - 31 August 2007	159,596
2007 – 2008	1 September 2007 - 31 August 2008	159,596
2008 – 2009	1 September 2008 - 31 August 2009	159,596
2009 – 2010	1 September 2009 - 31 August 2010	159,596
2010 – 2011	1 September 2010 - 31 August 2011	159,596
2011 – 2012	1 September 2011 - 31 August 2012	159,596
2012 – 2013	1 September 2012 - 31 August 2013	159,596
2013 – 2014	1 September 2013 - 31 August 2014	159,596
2014 – 2015	1 September 2014 - 31 August 2015	159,596
2015 - 2016	1 September 2015 - 31 August 2016	159,596

4.3 Quantifying GHG emissions and/or removals for the project scenario:

Power Density

The regulating pond was calculated as 178,000 m^2 while installed capacity of the power plant is 50 MW, therefore power density would be:

$$PD = \frac{Cap_{PJ} - Cap_{BL}}{A_{PJ} - A_{BL}} = \frac{50{,}000{,}000 - 0}{178{,}000 - 0} = 281\ W/m_2 \qquad (12)$$

According to ACM0002 version 10, no project emissions have to be taken into consideration as the power density exceeds 10 W/m^2. Therefore there are no emissions to consider that may have arisen from such a flooded area. Thus, $PE_y = 0$

Project Emission

$$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y} \qquad (12)$$

Parameter	Description	Unit	Value	Source
PE_y	Project emissions in year *y*	tCO_2e/yr	0	Equation (8)
$PE_{FF,y}$	Project emissions from fossil fuel consumption in year y	tCO_2/yr	0	“Tool to calculate project or leakage CO_2 emissions from fossil fuel
$PE_{GP,y}$	Project emissions from the operation of geothermal power plants due to the	tCO_2/yr	0	Project activity is not a geothermal power plant

$PE_{GP,y}$	Project emissions from the operation of geothermal power plants due to the release of non-condensable gases in year *y*	tCO_2/yr	0	Project activity is not a geothermal power plant

Project emissions from the consumption of fossil fuels

$PE_{FF,y} = PE_{FC,j,CO2}$, if $PE_{FC,j,CO2} > 1\%$ of total emission reduction. Otherwise $PE_{FF,y} = 0$ shall be applied following the methodology.

$$PE_{FC,j,CO2} = \Sigma FC_{i,j,y} \times COEF_{i,y} \quad (13)$$

Where:

Parameter	Description	Unit	Value	Source
$PE_{FC,j,CO2}$	CO_2 emissions from fossil fuel combustion in process j during year y	tCO_2/y	0.28	Equation 13
$FC_{i,j,y}$	Quantity of fuel type i combusted in process j during the year y	t Diesel/y	0.088	Sipansihaporas HEPP
$COEF_{i,y}$	CO_2 emission coefficient of fossil fuel type i in year y	tCO_2/t Diesel	3.1863	Equation 9
i	Fuel types combusted in process j during year y	-	i= Diesel oil	Sipansihaporas HEPP

The total $PE_{FC,j,CO2}$ over the ten year crediting period accounts for 2.8 t CO_2e while the total projected emission reductions are 1,595,964 t CO_2e. Since total $PE_{FC,j,CO2}$ accounts for less than 1% of the baseline emissions, and in accordance with ACM0002 version 10, the project emission can be neglected.

4.4 Quantifying GHG emission reductions and removal enhancements for the GHG project:

Leakage Emissions

According to ACM0002, the leakage of the proposed project is not considered. No leakage is expected. Therefore, $L_y = 0$.

$$L_y = 0$$

The ex-ante emission reductions calculations are as follows:

$$ER_y = BE_y - PE_y - L_y$$

Using the calculation above the total baseline emission for the 10-year crediting period is 1,595,960 tCO_2e or 159,596 tCO_2e/year, as shown in the summary below:

Summary of Emission Reduction (ER)

Years	Vintage	Project emission (tCO_2e)	Baseline emission (tCO_2e)	Leakage emission (tCO_2e)	Overall emission reductions (tCO_2e)
2006 - 2007	1 April 2006 - 31 March 2007	0	159,596	0	159,596
2007 – 2008	1 April 2007 - 31 March 2008	0	159,596	0	159,596
2008 – 2009	1 April 2008 - 31 March 2009	0	159,596	0	159,596
2009 – 2010	1 April 2009 - 31 March 2010	0	159,596	0	159,596
2010 – 2011	1 April 2010 - 31 March 2011	0	159,596	0	159,596
2011 – 2012	1 April 2011 - 31 March 2012	0	159,596	0	159,596
2012 – 2013	1 April 2012 - 31 March 2013	0	159,596	0	159,596
2013 – 2014	1 April 2013 - 31 March 2014	0	159,596	0	159,596
2014 – 2015	1 April 2014 - 31 March 2015	0	159,596	0	159,596
2015 - 2016	1 April 2015 - 31 March 2016	0	159,596	0	159,596
Total (tCO_2e)		0	1,595,964	0	1,595,960

5 Environmental Impact:

According to the Decree of the Ministry of Environment No. 17/2001, all hydroelectric power plants with a dam height of ≥ 15 meters, or flooded area of ≥ 200 ha or installed capacity of ≥ 50 MW need to undertake an Environmental Impact Assessment (EIA). Sipansihaporas Hydroelectric Hydroelectric Power Plant project has an installed capacity of 50 MW electricity in total and requires an EIA.

An EIA has been developed for this project and was completed in 1996 and approved by the Ministry of Energy and Mining on the 3 July 1996. Where impacts of the project were identified, mitigation measures were suggested and defined. The EIA highlights the following impacts in connection with the project, as shown in the table below.

Table D.1 Summary of EIA findings

Identified environmental impacts	Measures taken
Pre-Construction phase	
Social responsibility	
Community perception related to project consultation, publicizing and resettlement	Perform discussion with local community, give proportional compensation on resettlement of village, monitor the issues that develop in the community
Construction phase	
Air and noise pollution	
Increase of air and noise pollution due to increased transportation and operation of heavy equipment	Restrict the use of heavy equipment operation during the day, build project fence to reduce noise pollution, spray water to avoid dust from construction, control vehicle emission and noise, and use protective masks for employees
Water pollution	
Change in surface water flow due to land clearing and covering	Create a drainage system to the nearest water body, perform a gradual land covering based on project phase, and execute land clearing only on the project site.
Solid waste	

Construction waste from the transportation of soil material	Perform continuous cleaning during the construction period to remove debris and deposit of it appropriately
Biodiversity and ecosystems	
Change in biodiversity due to alteration in land and water body conditions	Reforest and restore the green lands after the construction, and maintain the minimum river flow to preserve the natural biodiversity within the river.
Employment impacts	
Utilization of local human resources	Give priority to local employment and hold special training to enhance the local community's skills.

Identified environmental impacts	Measures taken
Operation phase	
Water pollution	
Decrease in the quality and quantity of water due to the wastewater from plant's activity and land erosion	Operate wastewater treatment plant and reforest the watershed area
Environmental	
Related to the project operation and its supporting facility, solid waste and wastewater from the surrounding settlement	Build a wastewater treatment facility, execute a solid waste temporary disposal system and create a waste transportation system
Spatial planning	
Changing in spatial planning structure due to project activity	Control the development around project activity by enforcing the appropriate planning regulations
Regional image	
Changing in regional image due to the development in the region	Planning controls will ensure sensitive development of the region
Traffic	
Increase traffic activity due to the project's operational activity	Restore the trans-Sumatra main road and set up traffic signs
Health and Safety	
Human resources needed to operate the project and its facilities	Give employment opportunities to local human resources following high health and safety standards
Working opportunity and income	
Related to utilization of local human resources	Give priority to the admission of local human resources and hold special training session to enhance the local community's skills.
Comfort	
Uncomfortable conditions due to vehicle's activity on the access road from and/or to the project	Maintain the road condition by setting-up traffic signs and planting trees on the roadside
Social responsibility	
Community perception related to project operation	Give donation for community, build a kindergarten in the nearest village and reforestation

With mitigation controls planned as part of the project construction and EIA process, and the contribution made by the project to sustainable development for the local and national area, the project is expected to have an overall positive impact on the local and global environment. All negative environmental impacts are subject to mitigation measures as described above.

6 Stakeholders comments:

A meeting with relevant stakeholders, including the village chief, local leaders, local organisation, NGO and people who live nearby, within the project boundary of Sipansihaporas hydro power plant was conducted for the purpose of the significant impact in the region due to the project, possible positive and negative impact due to the project and to understand stakeholder perceptions due the project.

As documented, the local stakeholders have perceived that the construction of Sipansihaporas Hydro has increased their social and economical life due to road construction, additional earning from temporary jobs, and especially due to the additional supply of electricity.

The stakeholder meeting was carried out in 17 September 2004 in the village hall of the Sipan village. The meeting was documented and recorded. Attendance list, pictures, and other relevant documentation will be made available to the DOE and sent separately.

No negative comments were received from the local stakeholders during the meeting. They did not object to the project activity because the project will not negatively impact the surrounding environment or people. The project also does not require any major displacement of local population. The project activity has acquired land from local population and local populations have been given compensation for this. So project activity has not received any adverse comment from their side.

No major issue which would affect the life of the local community or raise any environment related problems in the region by the implementation of the project activity were identified during the discussion with stakeholders. All the minor issues were addressed.

7 Schedule:

Project start date:
Sipansihaporas hydro power plant Unit 1: 14 December 2004
Sipansihaporas hydro power plant Unit 2: 21 October 2002

Thus, the project start date where project activity starts reducing emissions is 21 October 2002, as the earliest project start date of two units at Sipansihaporas Hydro Power Plant.

Crediting period start date as per VCS 2007.1: 1 April 2006

Operational lifetime of project activity: 30 years

VCS crediting period: 10 years from 1 April 2006 until 31 March 2016

8 Ownership:

8.1 Proof of Title:

The contract agreement can be referred as the proof of the ownership of the project activity.

8.2 Projects that reduce GHG emissions from activities that participate in an emissions trading program (if applicable):

Not applicable. PP has not participated in any other GHG emission credit program.

9 Annex: