Project design document form

(Version 10.1)

Complete this form in accordance with the instructions attached at the end of this form.

BASIC INFORMATION	
Title of the project activity	Asahan 1 Hydroelectric Power Plant 2 x 90 MW
Scale of the project activity	☒ Large-scale ☐ Small-scale
Version number of the PDD	4.0
Completion date of the PDD	21/02/2018
Project participants	PT Bajradaya Sentranusa
Host Party	Republic of Indonesia
Applied methodologies and standardized baselines	ACM0002: Grid-connected electricity generation from renewable sources --- Version 17.0
Sectoral scopes linked to the applied methodologies	1
Estimated amount of annual average GHG emission reductions	1,021,075

SECTION A. s Description of project activity

A.1. Purpose and general description of project activity

>>
Asahan 1 Hydroelectric Power Plant 2 x 90 MW Project (hereafter referred to as the "Project"), developed by PT Bajradaya Sentranusa (hereafter referred to as the "Project Developer"), is a run-of-river hydroelectric power project in North Sumatera Province in Indonesia (hereafter referred to as the "Host Country"). The Project uses the existing flow of Asahan River to produce electricity and it has no large scale dam or reservoir build for the project, as it is a run-of-river hydroelectric power plant.

The Project is taking advantage of Asahan River flow that receives water from its natural source, Lake Toba. Geographically, the Project is located downstream of Lake Toba and upstream of the existing Asahan 2 (Siguragura) hydroelectric power plant, a large dam power plant built in 1981[1]. The objective of this Project is to supply zero emission energy to Sumatera Grid (hereafter referred to as the "Grid"), a grid with relatively carbon-intensive electricity supply that is located in Sumatera island and currently has no interconnection with the grid in other islands e.g. Java, Kalimantan.

The natural lake with 1,103 km2 area[2] gives an annual available discharge to the Project. The total installed capacity of the Project will be 180 MW, consisting of 2 x 90 MW turbines, with a predicted power production of 1,175,000 MWh per annum[3] to be delivered to PLN as the primary energy and 100,000 MWh per annum is estimated as the secondary electricity generation. The electricity currently generated by the Grid has an operating margin emission factor of 0.676 tCO2/MWh and a build margin emission factor of 0.933 tCO2/MWh, thus giving a combined margin of 0.869 tCO2/MWh[4]. The predominantly fossil fuel based electricity generated in the Grid is the baseline (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 is then expected to reduce emissions of greenhouse gases by an estimated 945,875 tCO2e per year during the first crediting period and 1,021,075 during the second crediting period.

The project complies with sustainable development criteria as required by the host country:

- Environmental Criteria

The project makes good use of run-of-river technology that will positively generate renewable energy sources whilst helping to sustain and preserve its natural environment.
□□The project alleviates the dependency of fossil fuel use in energy sectors; it is thus improving the air quality

- Economic Criteria

The project will increase employment opportunities in the area where the project is located (local people that have qualified skills will be permanently employed for the project operation and project construction will generate temporary jobs in the construction sector). Around 70% of the total unskilled workers of 600 to 900 persons are hired from the local residents, while during the operational stage, it is expected that approximately 30 people will be hired from the local community.

- Social Criteria

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[1] Departemen Pekerjaan Umum Republik Indonesia (2008), Informasi dan Data Bendungan Siguragura, Available from: http://sda.pu.go.id/bendungan_detail.php?idw=51, [Accessed 1 April 2009]

[2] World Lakes Organization, Experience and Lessons Learned Brief for Lake Toba. Available from: http://www.worldlakes.org/uploads/Toba_12.07.03.pdf , [Accessed 7 May 2009]

[3] Power Purchase Agreement (PPA) page 12 (definition of Take or Pay Energy)

[4] Taking OM weight of 0.25 and BM weight of 0.75 as required for the second crediting period.

The project will implement a local community development program, including the construction of a small dam for drinking water supply in Ambarhalim village, donate loudspeaker equipments to Senior High School at Pintu Pohan village and level the school yard at Tangga village.

- Technology Criteria

The project will diversify the sources of electricity generation, thus improving security of supply, which is important for meeting growing energy demands and the transition away from diesel and coal-supplied electricity generation

Prior to the operation of this hydro power plant a series of training programs will be implemented as part of the recruitment program. The training of these staff will be focused on the operation and maintenance of the power plant.

The project will contribute to development of technological capacity building in the country as the technology is being introduced and consolidated with local engineers as well as local labour who work on the construction.

This PDD is for the second crediting period of the project activity. The first crediting period runs from 01/03/2011 to 28/02/2018.

A.2. Location of project activity

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Village of Siruar (Siantar Utara), Ambar Halim and Simorea Sub District of Parmaksian and Pintu Pohan Meranti Region of Toba Samosir, North Sumatra, Indonesia.

The project is located at GPS coordinates of N 2°29’53” and E 99°12’23”, with the exact location of power house and intake as follow:

Intake location: L: 2° 29' 23" North - 99° 12' 25" East

R: 2° 29' 21" North - 99° 12' 28" East

Power house location:

2° 30' 45" North - 99° 15' 33" East

It is sited on the Asahan river where it can be reached by land transportation (car) from Medan, capital city of North Sumatera Province, through Pematang Siantar and Porsea. An international airport is available in Medan. See the following illustration for project location:

A.3. Technologies/measures

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The Project is a run-of-river hydroelectric power plant with capacity of 180 MW, consisting of 2 x 90 MW turbines, located upstream of Asahan 2 Power Station (Siguragura Dam). The available head for the project is 170.1 m (gross head at power plant). Lake Toba is located upstream of the project with coverage area of 1,103 km^2 and an effective storage capacity[5] of 2.86 x 10^9 m^3. A regulating dam built for Asahan 2 power station in 1983[6] is located between the Project and Toba Lake, called the Siruar Dam. This dam has drainage area4 of 3,674 km^2.

The Project uses well established hydroelectric power generation technology for electricity generation. It is a diversion-type, run-of-river hydroelectric power project, with an operation lifetime of 30 years. The electricity voltage will be increased by using step-up transformers of 275 kV and will be transmitted to PLN Grid System (Sumatera Grid).

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

Table A.4.3.1 - Main technical parameters of the proposed project

Parameter	Capacity	Source
Installed capacity (MW)	180	PPA[7] page 1
Expected annual electricity generation / net export electricity (effective/primary supply to the Grid) (MWh)	1,175,000	PPA Appendix A, page A-6
Expected secondary/excess electricity generation (supply to the Grid) (MWh)	100,000	PPA Appendix A, page A-6 (30% was accounted in the Feasibility Study, as demonstrated by Project Developer in their model, but 100% will be accounted for the financial calculation in
Water head, gross head at power plant (m)	170.1	PPA Appendix A, page A-5
Plant discharge capacity (m^3/s)	125.8	PPA Appendix A, page A-5

[5] Appendix A of Power Purchase Agreement (PPA)

[6] UNESCO – IHP Publication. Catalogue of Rivers for South East Asia and The Pacific, Available at: http://flood.dpri.kyoto-u.ac.jp/ihp_rsc/riverCatalogue/Vol_02/index.html [Access on 30 April 2009]

[7] PPA is Power Purchase Agreement, agreed between Project Developer and PLN (PLN is Perusahaan Listrik Negara or National Electricity Company, a state owned electricity company in the Host Country)

According to the PPA, the electricity generated to an amount of 1,175 GWh will be sold under an agreed tariff and will be termed as Primary energy. The amount of electricity exceeding 1,175 GWh will be sold under a different tariff than the primary energy and will be termed as Secondary energy. This categorisation of energy in the PPA will result in different slabs of tariff to be applied and only serve for invoicing purpose while all energy sent to the Grid will be monitored through the same meter, as described in Section B.7, with no regards on categorisation of the energy itself.

The estimation of the electricity exceeding 1,175 GWh is based on availability of water flow obtained from the historical data of hydrological condition of Asahan River, in which the optimist figure would be an addition of 100 GWh per year. However, due to the river flow availability of 74.5%, it is unlikely that the excess electricity generation will be more than 30% of the optimist figure. The hydrological information is obtained from Asahan 2 power plant which was built in 1981 and comprises of 70 years hydrological data. The same has been used by the Project Developer to estimate the revenue and do their investment analysis in the Feasibility Study. According to the PPA, expected operational hours of the project activity is 8,376 hours per year for each unit, which is based on the Scheduled Outage period of 360 hours/unit/year and Forced Outage period of 24 hours/unit/year. For certain years, the operational hour is decreased to 8,016 hours per year for each unit due to the increased amount of planned Scheduled Outage.

In general, the principal features in the Project are the Intake, Headrace Tunnel, Surge Tank, Penstock, Tailrace, Powerhouse, Switchyard and Transmission lines of double-circuit line.

Due to the topographical and geological conditions, the whole waterway, headrace and penstock have been designed as pressure tunnel and placed underground. The optimum diameter of the headrace tunnel has been determined to be 6,518 m in length and the penstock diameter of 6 (for upper horizontal section) with 275 m in total length. The headrace tunnel is a one lane concrete-lined pressure tunnel, while the Surge Tank is a restricted orifice type steel surge tank.

The power house, however, will be placed above ground and shall be built on firm rocks in the existing Siguragura reservoir. The two 90 MW turbines and generators will be installed in that power house while the switchyard will be located on the wide-open terrace west of the powerhouse. Type of turbines used in the Project is vertical shaft type of Francis model with rated output of 92,300 kW each and it will be connected to the generators of three-phase, vertical shaft, semi-umbrella type with rated capacity of 100,000 kVA each and power factor of 0.9.

Below are technical parameters of the Turbine, Generator and Transformer:

Table A.4.3.2 - Technical parameter of Turbine and Generator

Technical Parameter	Capacity	Unit
Turbine (Vertical shaft, single runner type)		
Rated output	92,300	kW
Rated speed	300	
Rated head	163.5	m
Rotation	clockwise	
Generator (Vertical shaft, suspended type generator)		
Rated capacity	100,000	KVA
Rated voltage	13.8	kV
Rated current	4,183.7	A
Rated frequency	50	Hz
Rated power factor	0.90 lagging	
Transformer (Three-phase two winding, sealed, oil immersed, forced – oil – circulation, forced-air-cooled outdoor use)		
Rated power	2 x 100,000	KVA
Rated voltage primary winding	13.2	kV
Rated voltage secondary winding	288.8; 281.9; 275.0; 268.1; 261.2	kV
Impedance voltage	14% on rated power	

Source: PPA and Presentation of Generator Type Selection of Asahan I HEPP

A.4. Parties and project participants

Parties involved	Project participants	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Republic of Indonesia (host Party)	PT Bajradaya Sentranusa (Private entity)	No

A.5. Public funding of project activity

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The project will not receive any public funding from Parties included in Annex I of the UNFCCC.

A.6. History of project activity

>>

The project activity was registered as a CDM project activity on 01/03/2011 with a date of registration action of 21/06/2011 and with a renewable crediting period. This PDD is for the second crediting period. The project activity is not registered as a component project activity (CPA) in a registered CDM programme of activities (PoA).

A.7. Debundling

>>

Not applicable (large scale project activity)

SECTION B. Application of selected methodologies and standardized baselines

B.1. Reference to methodologies and standardized baselines

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ACM0002: Grid-connected electricity generation from renewable sources --- Version 17.0

Tools referenced in this methodology:

- Tool for the demonstration and assessment of additionality v05.2 (this is the version applicable at the first crediting period validation as this section of the PDD remains unchanged)
- Combined tool to identify the baseline scenario and demonstrate additionality v02.2 (this is the version applicable at the first crediting period validation as this section of the PDD remains unchanged)
- Tool to calculate project or leakage CO2 emissions from fossil fuel combustion Version 03.0
- Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation Version 03.0
- Tool to calculate the emission factor for an electricity system Version 06.0
- Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period Version 03.0.1

B.2. Applicability of methodologies and standardized baselines

>>
The Applicability conditions of the ACM0002 (Version 17) and compliance of the project activity with these conditions are explained in the table below:

Para	Applicability condition	Compliance
3	This methodology is applicable to grid-connected renewable energy power generation project activities that: (a) Install a Greenfield power plant; (a) Involve a capacity addition to (an) existing plant(s); (b) Involve a retrofit of (an) existing operating plants/units; (c) Involve a rehabilitation of (an) existing plant(s)/unit(s); or (d) Involve a replacement of (an) existing plant(s)/unit(s).	The project activity is the installation of a new hydroelectric power plant at a site where no renewable power plant was operated prior to the implementation of the project activity. The project is connected to the Sumatra grid. This criteria is applicable to project activity. • Greenfield grid-connected renewable power generation project
4	The methodology is applicable under the following conditions: (a) The project activity may include renewable energy power plant/unit of one of the following types: hydro power plant/unit with or without reservoir, wind power plant/unit, geothermal power plant/unit, solar power	Hydro power plant. Not a capacity addition. This criteria is not applicable to project activity.

	plant/unit, wave power plant/unit or tidal power plant/unit; (b) In the case of capacity additions, retrofits, rehabilitations or replacements (except for wind, solar, wave or tidal power capacity addition projects the existing plant/unit 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, retrofit, or rehabilitation of the plant/unit has been undertaken between the start of this minimum historical reference period and the implementation of the project activity.	
5	In case of hydro power plants, one of the following conditions shall apply: (a) The project activity is implemented in existing single or multiple reservoirs, with no change in the volume of any of the reservoirs; or (b) The project activity is implemented in existing single or multiple reservoirs, where the volume of the reservoir(s) is increased and the power density calculated using equation (3), is greater than 4 W/m2; or (c) The project activity results in new single or multiple reservoirs and the power density, calculated using equation (3), is greater than 4 W/m2; or (d) The project activity is an integrated hydro power project involving multiple reservoirs, where the power density for any of the reservoirs, calculated using equation (3), is lower than or equal to 4 W/m2, all of the following conditions shall apply: (i) The power density calculated using the total installed capacity of the	The project activity is implemented in an existing reservoir with no change in the volume of the reservoir (the project is required to maintain the water level of the existing reservoir). As such the project activity is in compliance with the methodology under 5 (a).

	integrated project, as per equation (4), is greater than 4 W/m2; (ii) Water flow between reservoirs is not used by any other hydropower unit which is not a part of the project activity; (iii) Installed capacity of the power plant(s) with power density lower than or equal to 4 W/m2 shall be: a. Lower than or equal to 15 MW; and Less than 10 per cent of the total installed capacity of integrated hydro power project.	
6,7,8	In the case of integrated hydro power projects, project proponent shall: Demonstrate that water flow from upstream power plants/units spill directly to the downstream reservoir and that collectively constitute to the generation capacity of the integrated hydro power project; or Provide an analysis of the water balance covering the water fed to power units, with all possible combinations of reservoirs and without the construction of reservoirs. The purpose of water balance is to demonstrate the requirement of specific combination of reservoirs constructed under CDM project activity for the optimization of power output. This demonstration has to be carried out in the specific scenario of water availability in different seasons to optimize the water flow at the inlet of power units. Therefore this water balance will take into account seasonal flows from river, tributaries (if any), and rainfall for minimum five years prior to implementation of CDM project activity.	The project is not an integrated power project. This criteria is not applicable to project activity.
9	The methodology is not applicable to: (a) Project activities that involve switching from fossil fuels to renewable energy sources at the site of the project activity, since in this case the baseline may be	The project activity is not fuel switch or biomass. This criteria is not applicable to project activity.

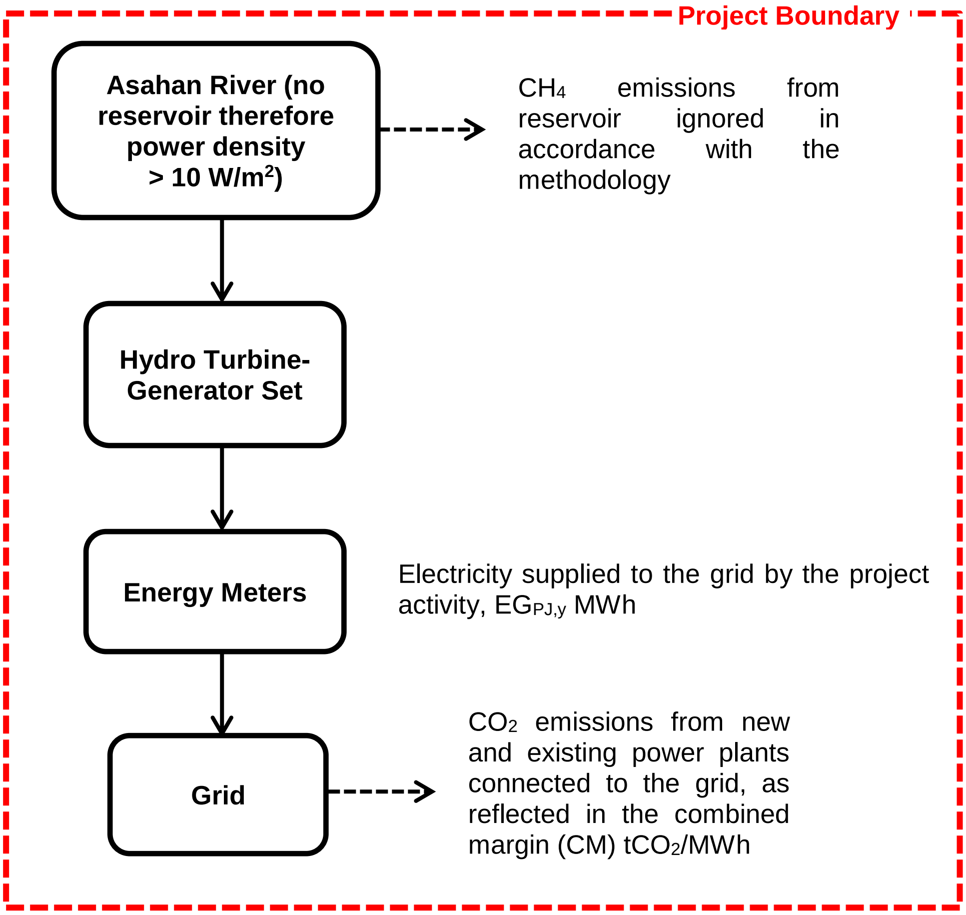
	the continued use of fossil fuels at the site; (b) Biomass fired power plants/units.	
10	In the case of retrofits, rehabilitations, replacements, or capacity additions, this methodology is only applicable if the most plausible baseline scenario, as a result of the identification of baseline scenario, is "the continuation of the current situation, that is to use the power generation equipment that was already in use prior to the implementation of the project activity and undertaking business as usual maintenance".	The project activity is not a retrofits, rehabilitations, replacements, or capacity addition. This criteria is not applicable to project activity.

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

>>

Source		GHGs	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
		CH_4	No	Minor emission source
		N_2O	No	Minor emission source
Project activity	For Hydro: Emission of CH_4 from reservoir	CO_2	No	Minor emission source
		CH_4	No	There is no new single or multiple reservoirs and no increase of single or multiple reservoirs resulting from the project activity. Thus in line with ACM0002 version 17 the calculation for power density is not applicable and no greenhouse gas emissions from this source are considered.
		N_2O	No	Minor emission source

Schematic Diagram of Hydro Power Plant:



B.4. Establishment and description of baseline scenario

>>

This PDD relates to a request for renewal of a crediting period. In line with paragraphs 287 – 290 of the CDM project standard for project the project participants are not required to re-assess the baseline scenario. Rather the project participants shall assess the GHG emission reductions that would have resulted from that scenario.

The project activity is the installation of a Greenfield power plant, and the baseline scenario is that the 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) described in the "Tool to calculate the emission factor for an electricity system". Below the steps of the Methodological tool "Assessment of the validity of the original/current baseline and update of the baseline at the renewal of the crediting period" are followed and the updating of the CM is outlined in step 1.4.

Step 1: Assess the validity of the current baseline for the next crediting period
Step 1.1: Assess compliance of the current baseline with relevant mandatory national and/or sectoral policies

If the current baseline complies with all relevant mandatory national and/or sectoral policies which have come into effect after the submission of the project activity for validation or the submission of the previous request for renewal of the crediting period and are applicable at the time of requesting renewal of the crediting period, go to Step 1.2.

This is the case as there is no legal obligation on the project proponents to proceed with the project activity.

Step 1.2 Assess the impact of circumstances
There have been no significant changes to the renewable energy and investment environment since the original validation. The only change is the revision of the grid emission factor outlined in Step 1.4.

Step 1.3 Assess whether the continuation of use of current baseline equipment(s) or an investment is the most likely scenario for the crediting period for which renewal is requested.
This step is not relevant to a greenfield installation as there was no existing equipment.

Step 1.4 Assessment of the validity of the data and parameters
The grid emission factor for the Sumatra grid must be updated. The Combined Margin for Sumatra has been calculated based on the Tool to calculate the emission factor for an electricity system by the Ministry of Energy and Mineral Resources of Indonesia (Kementerian Energi dan Sumber Daya Mineral Republik Indonesia or ESDM). The most recent figures, published in January 2016 lead to a Combined Margin of **0.869** tCO_2/MWh[8]. This figure will be used to update the factor EF_{grid} in this PDD.

B.5. Demonstration of additionality

>>
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" approved by the Executive Board (Version 05.2, EB 39)

In the assessment of additionality, it is important to note that CDM was seriously considered by the Project Developer. The project originally started construction on 6 June 1997[9], but was stopped at the stage of implementation due to the economic crisis in Indonesia in 1997-98. At that point of time Project Developer was only managed to construct the supporting facility for the power plant and had not done the main construction work towards the project. A PPA was initially signed between PLN and the project developer in December 1996, however with the economic crisis that emerged in Indonesia during 1997-1998, the project and PPA was suspended by a Presidential Decree in 1998. This put the project officially under review, and eventually the project failed to comply with its already secured financial arrangement from various financial institutions at that time. After a few years, the government cancelled the aforementioned Presidential Decree in 2002. With the cancellation of the Presidential Decree the legal limitation to not implement the project was lifted. It allows the Project Developer to restart the project with a revised PPA and financing arrangements. An amended PPA was signed in 2004 at a revised tariff to reflect the present economic conditions in Indonesia, in which the tariff is indicated in different currency than IDR. So to avoid the impact due to the exchange rate, the project financial estimation is done in same currency consistently. Internally, the board of director of the Project Developer has sent around a letter in 14 February 2005 that noted CDM as potential revenue in order to increase the financial attractiveness of the project. Project Developer then contacted EcoSecurities in mid 2005 to develop the project as a CDM project, while at the same time sought for additional financial support (see Table B.5.1 for detail), incorporating CDM revenue in their financial model.

8 http://www.djk.esdm.go.id/index.php/layanan-info-pub/2016-01-08-03-54-21/faktor-emisi-pembangkit-listrik and associated spreadsheets provided by ESDM taking W_{OM} and W_{BM} of 0.25 and 0.75 as applicable to the second crediting period as outlined in the Tool to calculate the emission factor for an electricity system

9 Based on the EPC contract signed in 6 June 1997

By mentioning CDM as one of its revenue in the Feasibility Study[10], and Board endorsing it[11], financial support was gained with the signing between Project Developer and China Huadian Engineering Corporation in the form of EPC Contract. Process of considering CDM was then finalised with the signing of basic Emission Reduction Purchase Agreement (ERPA) with EcoSecurities (dated 9 November 2007). After completing their verification process, the project is officially started its construction in 29 January 2007 based on the Certificate of Effectiveness to PPA[10] from PLN, however for CDM purpose the start date of the Project will be on July 2006 when they secured the agreement with China Huadian. Project is commissioned in June 2010, as shown in table of sequence below.

[10] Feasibility Study Report (FSR) is dated December 2005, Summary of FSR is available

[11] Minutes of Meeting dated 22 March 2006 of PT Bajradaya Sentranusa, document available during validation.

Table B.5.1 – Project Timeline

Date	Activity	Sources
October 1996	Issuance of Environmental Impact Assessment in the form of UKL/UPL[12]	UKL/UPL document
1998	Original Project is suspended as it is put under the category of “to be reviewed” by the President	Presidential Decree no. 5/1998
2002	Project is approved to continue by Presidential Decree	Presidential Decree no. 15/2002 Ministerial Decree No. 1439K/30/MEM/2002 (Minister of Energy and Mineral Resources of the Republic of Indonesia)
2002-2004	Continuous discussion between Project Developer and PLN to amend the original PPA	
8 January 2004	Project Developer and PLN agree on new tariff to amend the previous PPA	Amendment Agreement to PPA dated 23 December 1996
18 March 2004	Contract document for EPC	EPC Contract between Project Developer and China Huadian Engineering Corporation, with the validity subject to clause 9 of the contract up to 31 Dec 2004
31 December 2004	Date limit of EPC contract being effective	Clause 9 of the 18 March 2004 Contract (Effectiveness of Contract Subject to Financing)
31 January 2005	Financial analysis report for the project was circulated to the Board of Directors	Financial Feasibility Study – Analysis Report
14 February 2005	Board of Director decision to involve CDM in order to increase project	Circular Letter of Board of Director, dated 14 February 2005
5 September 2005	Project developer shows intention to develop the project as CDM project	Letter of Intent to Develop the project as a CDM Project and Purchase the Resulting CERs
27 September 2005	Communication with CDM consultant	Response of the Letter of Intent from EcoSecurities to the Project Developer
December 2005	Feasibility Study sent to China Huadian, as the prospective financial supporter, with CDM as one of its revenue sources making the project.	Feasibility Study
22 March 2006	Meeting to acknowledge how CDM revenue can increase project value and to participate in the CDM program	Minutes of Meeting dated 22 March 2006 of PT Bajradaya Sentranusa
12 June 2006	Issuance of Electricity Generation Permit by Directorate General of Electricity and Energy Utilization of Ministry of Energy and Mineral Resources (DJLPE)	Electricity Generation Permit (IUKU)
24 July 2006	China Huadian agrees upon the FS and will give financial support in the form of EPC work and equipment support (Financial closure which is considered as	EPC Contract
1 December 2006	Project Developer to received a term loan facility from China Huadian Hongkong Ltd.	Term Loan Facility document

[12] UKL is Environmental Management Procedure, UPL is Environmental Monitoring Procedure

21 December 2006	Issuance of Certificate of Effectiveness for construction start date of the project as agreed by PLN and Project Developer	Certificate of Effectiveness of Amendment to PPA
29 January 2007	Project officially starts construction.	Certificate of Effectiveness of Amendment to PPA, by PLN, allowing the project to commence on the aforementioned date
30 July 2007	Project developer response letter regarding proposal of CDM development	Letter of Response regarding EcoSecurities proposal for the CDM of Asahan-1 HEPP (2x90MW)
9 November 2007	Basic Emission Reduction Purchase Agreement signed	Basic Agreement of ERPA with EcoSecurities
27 December 2007	Continuation of agreement with China Huadian	Amendment and Restatement of EPC Contract
17 April 2008	Presentation of project progress	Project progress presentation
22 July 2008	Presentation of project progress	Project highlight and summary (progress)
9 October 2008	Project developer participation in Carbon Finance Asia 2008	Project developer participated as a speaker in the seminar
28 November 2008	EB approval for ACM0002 ver.8	
December 2008	PDD development	
13 February 2009	EB approval for ACM0002 ver.9	
18 March 2009	Stakeholder Consultation	Stakeholder consultation report
28 May 2009	EB approval for ACM0002 ver.10	
23 June 2009	Project developer participation in Carbon Market Asia 2009	Project developer participated as a speaker in the seminar

28 June 2010	Project operation	Commissioning certificate

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

The baseline is defined in the 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 CDM-related income, through the sale of generated electricity, Option I (Simple Cost Analysis) is not applicable.

According to the Additionality Tool, if the alternative to the CDM project activity does not include investments of comparable scale to the project, then Option III must be used. Given that the alternative is the continuation of supply of electricity from the Grid, benchmark analysis (Option III) is then used for assessing the financial attractiveness of the project activity.

Sub-step 2b: Option III – Application of benchmark analysis

The Internal Rate of Return (IRR) will be used as the most appropriate financial indicator for the analysis. The likelihood of the development 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) with an appropriate benchmark.

The benchmark should be based on parameters that are standard in the market, considering the specific characteristics of the project type, but not linked to the subjective profitability expectation or risk profile of a particular project developer. All financial information used for benchmark determination is publicly available and can be clearly validated by a DOE. The benchmark is therefore derived from market returns and government bond rates in the Host Country, increased by a suitable risk premium to reflect private investment in the electricity generation sector. The risk premium applied reflects the risk of the project activity being assessed as required by the "Guidance on the assessment of investment analysis" but does not relate to an 'internal benchmark' that would apply an individual's perception of risk involved in the project activity or individual profit expectations. Given the project specific context, a weighted average cost of capital (WACC) is used as the appropriate benchmark to compare with the project's return.The selected approach is widely accepted as a suitable approach among financial managers to take investment decisions.

Parameters used in benchmark determination for this financial analysis is summarised in the table below:

Table B.5.2 – Values taken for benchmark determination

Parameter	Value	Source
Market return	24%	Jakarta Composite Index (tab 'market return' in the worksheet)
Risk free rate	11.25 %	Indonesian Government Bond, average value of year 2005[13]
Equity Risk premium	12.61 %	Calculated as the difference of historic average of market return of Jakarta Composite Index (24%)[14] and the historic average of riskless investments for period 2001-2006 (11.3%)[15]
Electricity generation asset Beta (unlevered)	0.96	Stern School of Business, New York University[16]
Electricity generation asset Beta (levered)	1.67	Calculated with the D/E and tax rate of the sector (Levered Beta = Unlevered Beta*(1+ (1 - Tax Rate) * Debt/Equity))
Tax rate	30 %	Indonesian National tax regulation[17]
Cost of Equity (CAPM)	32.32%	Calculated
D/E	106%	D/E ratio for the Electricity generation companies in Emerging Economies[18]
Debt ratio	51.5 %	Average industry debt ratio
Cost of debt	8 %	Indonesian central bank statistic webpage[19]
WACC	18.56 %	Calculated

The formula applied to calculate the WACC is the following:

[13] Indonesian Government Bond interest rate, Bloomberg Finance L.P, Bloomberg professional service

[14] Market index return, Bloomberg Finance L.P, Bloomberg professional service

[15] Average interest rate based on Indonesian Government Bond interest rates, 2002-2006, Bloomberg Finance L.P, Bloomberg professional service

[16] In order to estimate the applicable beta, market information compiled by a finance professor of a business school is used. (http://www.stern.nyu.edu/~adamodar/). The underlying data is provided by Bloomberg Finance L.P. Due to unavailability of betas from power sector companies in the host country, all available information is used. All available information comprises regionally all 'emerging economies' and functionally the 'electricity-generation' sector as the sector closet related to the project activity. This approach is build on the assumption that the relative risk (to a well diversified efficient portfolio) of the investigated sector is similar across all regions, i.e. a power sector investment has similar relative risk in Indonesia and in India for instance). This assumption has been taken in order to estimate the relative risk of a power sector project in a market in which there is no information available about power sector betas. Departing from the levered beta, corresponding market debt to equity ratio and tax rate, every firm's asset beta is calculated. The average value of all these asset betas is applied as input value to estimate the cost of equity of the project type.

[17] Indonesian Government (2000), Perubahan ketiga tentang Undang-undang no. 7/1983 tentang Pajak Penghasilan (Third Revision of Government Law no 7/1983 about Income Tax), [Online] Undang-undang no. 17/2000 (Government Law no. 36/2008), in effect since 1 January 2001, Available from: http://www.setneg.go.id/index.php?option=com_perundangan&id=228&task=detail&catid=1&Itemid=42&tahun=2000. Accessed: 3 June 2009

[18] The average market of debt to equity ratios of all firms that were used to calculate the average sector asset beta is used as the applicable financing structure

[19] 2005 data for US Dollar loan interest rate averaged 8.22 % (this value was conservatively taken as 8%)

WACC[20] = Cost of Equity (%) x (1 - Debt Part (%)) + Cost of Debt (%) x Debt Part (%) x (1- Tax rate)

Determination of "Cost of Equity"
The cost of equity is determined by utilizing the Capital Asset Pricing Model (CAPM). The CAPM defines the compensation of investors for investments taken. One part of the formula is related to the time value of money (risk free rate) compensating for investment over a time period, the other part represents the risks for investment. This is calculated by taking a risk measure, so called beta (β). The beta compares the returns of the asset to the market over a period of time and to the market premium. The formula
correctly applied is as following:

Cost of Equity = Risk Free Rate + beta x (Market return - Risk free rate)
= Re = Rf + β x (Rm – Rf)

Where:
Re: Cost of equity
Rf: Risk free rate β:
Beta
Rm: Expected market return

The applied model is internationally known[21] and applied in making investment decision.

Rf: 11.25 %
The risk free rate is determined as an average of 5 government bond rates from Indonesia issued for a period of up to 15 years and published in the year 2005. These bond rates were available at the time of making the investment decision. The data to calculate the Risk free rate is sourced from Bloomberg Finance L.P.; Bloomberg professional service. The Bloomberg snapshot and the calculation of the Risk free rate can be found in the government securities tab in the calculation spreadsheet.

β: 1.67
The Beta value has been calculated based on sector information as compiled by a finance professor of Stern School of Business, New York University and provided by Bloomberg Finance L.P. Due to the lack of publicly available information in the host country, the project participant chose the Beta of the electricity generation sector in emerging economies. The approach is built on the assumption that the relative risk (compared to a well diversified efficient portfolio) of a sector is similar across all regions.
This assumption has been used in order to estimate the relative risk of a power sector project in a market in which there is no information available about power sector betas. This approach is provided on page no. 129 in the book "Valuation of companies in emerging markets: a practical approach" - Luis E. Pereiro[22]. The financial approach described in the page 129 of the book substantiates that an average beta calculation for the group of companies (representing a sector) in the Emerging Economies could represent a sector beta (e.g. power sector in our case). The average beta value (0.96) is then levered with the average D/E ratio (51.5%- average debt ratio) of the energy generating companies and the tax rate (30%) to get the levered beta (1.67). The

[20] http://www.investopedia.com/terms/w/wacc.asp

[21] http://www.investopedia.com/terms/c/capm.asp

[22] http://books.google.co.in/books?id=pv9GE3178pAC&printsec=frontcover&dq=Valuation+of+companies+in+emerging+markets+%2B+Luis+E.+Pereiro&source=bl&ots=Uj9SqnuMh&sig=Ulgw6NaUbsema1sfCaSew80Uio&hl=en&ei=yP8yTK7oJpOzrAfT1832Bg&sa=X&oi=book_result&ct=result&resnum=7&ved=0CDIQ6AEwBg#v=onepage&q&f=false

levered beta is derived in the “beta05” tab in the calculation spreadsheet and was used in CAPM to get the cost of equity.
The Beta value of each company is Unlevered with the debt equity ratio and the applicable tax rates of each company considered to get the respective Asset beta in the emerging economy as shown in the tab “Beta05” in the calculation spreadsheet attached with the response. The unlevered beta is the beta of the company without any debt.

Rm: 24 %
The market return is calculated based on the Jakarta Composite Index (JCI) and was used in the Capital Asset Pricing Model (CAPM) to calculate the cost of equity as shown in the Equation below. The information on the stock movement of the Jakarta Composite Index was extracted from Bloomberg Finance L.P (Bloomberg Finance L.P.; Bloomberg professional service). The compounded return for the market is calculated over a time period of 5 years (January 2001-January 2006) to determine the market return. Furthermore, the project participant also investigated another Index at Jakarta Stock Exchange – the LQ 45 - that comprises 45 most liquid stocks in the host country. The market return for LQ 45 is also calculated for the same period (January 2001- January 2006). It is concluded that it is higher than the market return of the JCI (24%). To ensure conservativeness the lower value has been chosen.

Cost of Equity as per CAPM approach:
Cost of Equity = Re = Rf + β x (Rm – Rf)
= 11.25% + 1.67 x (24% - 11.25%) = 32.32%

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

A financial analysis was then carried out following the benchmark determination. The parameters presented in the table B.5.3 have been used to conduct the financial analysis. The financial analysis does not include the equity spent by project developer and thus lowering the total investment value. This approach is applied for conservativeness consideration to show that the proposed project activity is not economically attractive.

Table B.5.3: Economic parameters used in the project

PROJECT DATA			*Source*
Expected COD[23]	Yr	2010	-
Emission Reduction	tCO_2	873,025	CER calculator
Primary Energy (TOPE[24])	MWh/yr '000 or (MN KWH)	1,175	PPA
Tariff Applicable to Primary Energy	US cents/kwh	4.60	PPA
component A of tariff	US cents/kwh	4.09	PPA
component B of tariff	US cents/kwh	0.36	PPA
component C of tariff	US cents/kwh	0.04	PPA
component D of tariff	US cents/kwh	0.11	PPA
Secondary Energy (non TOPE[25])	MWh/yr '000 or (MN KWH)	100.00	PPA
Tariff Applicable to Secondary Energy	US cents/kwh	2.10	PPA

[23] COD is Commercial Operation Date of the Project Activity

[24] Take-or-Pay Energy (TOPE) means the quantum of energy which would be expected to be generated by the Plant which is expected to be 1,175 GWh per year after Commercial Operation Date assuming that the Plant has the benefit of the discharge of Water into the Plant equal to Firm Average Discharge and assuming 95 percent availability of the Plant (definition taken from PPA)

[25] Non-Take-or-Pay Energy (Non TOPE) means any net electrical output after the Commission Date in excess of Take-or-Pay Energy

FINANCIAL PARAMETERS			Source
time span for assessment period	years	30	PPA
Rate of increase of tariff (on Component B and D)	% p.a.	2.5%	PPA
Income Taxes	%	30%	National tax regulation
Depreciation	% p.a.	5.00%	National tax regulation
Price of carbon	US$/tCO2	14.00	Market value
Validation and registration costs	US$	150,000	Market value
Verification costs	US$	10,000	Market value

COSTS AND EQUIPMENT (US$)			Source
a) Investment cost			
Pre-operational Costs	US$ (Mn)	0	
EPC Cost and insurance	US$ (Mn)	202.06	Feasibility study, EPC Contract
Non EPC Cost and Provisional Sum	US$ (Mn)	16.5	Feasibility study, Term Loan Facility
Interest during construction (IDC)	US$ (Mn)	30	Feasibility study, EPC Contract
Total New Investment to recommence project	US$ (Mn)	248.56	Feasibility study, EPC Contract (sum of the above rows). Value applied in investment analysis.
Capital Expenditures before the recommencement of the project activity (recoverable assets)	US$ (Mn)	110.95	Feasibility study(not considered in the cashflow)
Total Project Cost	US$ (Mn)	359.91	Feasibility study (the total cost is not considered in the cashflow)
b) Operating cost			
Fixed operating costs	US cents/kwh	0.36	PPA
Variable operating costs	US cents/kwh	0.11	PPA
Water and Hydro Facility Charge (pass through)	US cents/kwh	0.04	PPA
Escalation	%	2.5%	PPA

LOANS			Source
Loan Amount	US$ (Mn)	249	Sum of EPC Costs, Non EPC Costs and IDC
Debt Ratio	%	69.14%	Calculated value
Interest Rate	%	7.5%	EPC Contract (which incorporates the Loan component)
Number of half-yearly installments		22	EPC Contract (which incorporates the Loan component)

Calculation of the IRR is based on the annual cash flow which considered the annual revenue of produced electricity, yearly operating cost, and investment cost. The table below shows the financial analysis for the project activity without and with carbon finance. As shown, the IRR (without carbon: 15.72 %), is lower than the benchmark rate, which is 18.56 % as explained above. CDM in this regard is considered important as it will alleviate the low IRR and help the project in advancing that.

Table B.5.4 – Summary of project financial analysis result

	With CDM	Without CDM
IRR	19.19 %	15.72 %
Benchmark	18.56 %	

Significant accounting methods applied in the investment analysis are described below:

Income Tax and Depreciation:

The income tax rate applied in the investment analysis is 30%, while the depreciation rate applied is 5%. These values are based upon the national tax regulations , made effective 1 January 2001. According to Article 11, Clause 6, of the Regulation, the useful lifetime and the depreciation tariff of tangible assets is determined as according to a provided tariff table (please refer to Annex 7 for the original table and its translation). The project activity is categorized as a Permanent Building for Tangible Assets that has a useful lifetime of 20 years with a depreciation tariff of 5%. Taking into account the national tax regulations, the project will be completely devalued after 20 years, with a residual book value of zero, and salvage value need not be considered.

The potential remaining economic value of the project is only based on the effective length of the PPA of 30 years. The 30 years period with a secured source of revenue potential appropriately defines the investment analysis period and decision making basis of the project. The reasonable expectation on realization of assets beyond this period is considered zero as there is no book value or a reasonable expectation of economic value that can be quantified in absence of a PPA.

A theoretical option of applying perpetuity[26] to the cash flow as a method of valuation of residual value of the project activity at the end of the investment analysis of 30 years, assuming the continuation of cash flows indefinitely, would result in the Internal Rate of Return to change marginally from 15.72% to 15.86%. This is an unrealistic scenario as this assumes that a new PPA is in place and cash flows are consistent and indefinite. Nevertheless, this conservative approach demonstrates that even with perpetual cash flows, the Internal Rate of Return would not change significantly,

Investment Cost:

Based on the Feasibility Study, dated December 2005, the project costs denominated in USD were assessed as follows:

Table B.5.5 – Project Cost Breakdown

Project Cost Breakdown	Value (in Million USD)
A. Total Project Cost	359.91
B. Capital Expenditures before the recommencement of the project activity (recoverable assets)	110.95
C. Additional Financing Required to recommence project	248.56
- New EPC Cost and Insurance	202.06

[26] The Perpetuity Business Valuation Method', Rosetta IT Solutions Ltd http://www.rosetta-it.com/site/content/view/74/

- Non-EPC Cost and Provisional Sum	16.5 0
- Interest During Construction (IDC)	30

From the total project cost of USD 359.91 Million and taking into account the recoverable value of capital expenditures incurred up to year 2005 of USD 110.95 Million, only the additional fresh investment of USD 248.56 million required to recommence the project activity was applied for the investment analysis. This is conservative and in accordance with paragraph 6 of the Guidance on the Assessment of Investment Analysis (ver. 2).

Inclusion of the capital expenditures prior to recommencement of the project activity in the investment analysis would significantly reduce the IRR from 15.72% to 10.06% as shown in Annex 6.

Sub-step 2d: Sensitivity analysis

A sensitivity analysis was conducted using assumptions that are conservative from the point of view of analysing additionality, i.e. the 'best-case' conditions for the project IRR were assumed by altering the following parameters: (1) project revenues (which are dependent on the electricity tariff or the quantity of electricity generation); (2) total investment, and (3) operational cost.

Different percentage variations have been considered in the above critical assumptions in order to see how the variations can affect the IRR and to show how robust is the IRR to those variations. Table B.5.5 summarizes the results of the sensitivity analysis, showing the variations needed in these key parameters in order for the IRR to reach the benchmark.

Table B.5.6 - Different parameters affecting the project's IRR

Scenario	% change	IRR (%)
Original		15.80 %
Increase in electricity generation	19%	18.59%
Reduction in investment costs	14%	18.57%
Reduction in Operational Costs	126%	18.56%

An increase in the tariff is not considered reasonable as a basis for deciding to invest in the project, since the tariff is already defined in the PPA, and future increases in the tariff are not in control of the project developer. Furthermore, inflationary increases in components B and D have already been considered in the financial analysis. An increase in electricity generation of the plant of more than 19% is also unlikely as it means that the capacity factor would be 97% which is not typical for a hydro power plant. Furthermore, historical data of the river flow shows that 42 % of the average flow in 20 years period is lower than the flow needed for the project activity thus having a constant increase of 19% in electricity generation is not likely to happen. Therefore, 19% variations in project revenue needed to gain higher and acceptable IRR are not reasonable.

A reduction of the investment costs is unlikely to occur, since construction and material prices have been steadily increasing in recent years, along with prices in the wider economy as reflected in annual inflation rates[27]. A 14% reduction in investment costs therefore is highly unlikely. The condition applies equally to reductions in operational costs for the same reason. With 100% variations for reduction in operational expenses, the IRR only climbs by 2.21% from the original IRR to 18%, which is still lower than the above mentioned benchmark. In addition, a reduction of

[27] Central Bank of Republic Indonesia, Inflation Report (Consumer Price Index), [Online] Available from: http://www.bi.go.id/web/id/Moneter2/Inflasi_/Inflasi+CPI. Accessed 22 November 2010

126% in operational expenses to reach the benchmark will result in negative operating which is clearly not possible considering the trend of inflation rates in the past years. .

These results show that the IRR will only reach the benchmark under very favourable circumstances that are highly unlikely to happen. Therefore the project overall is not financially attractive.

Step 4. Common Practice Analysis

Indonesia has an abundant amount of hydro resources that have not been fully utilised. According to the National Energy Policy, the potential capacity of hydro resources in Indonesia is 75,000 MW of which only 4,200 MW has so far been used to generate electricity (including captive power and private entities)[28]. 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. Analyse other activities similar to the proposed activity

The hydro Power plants can be classified or said to be similar on the basis of their capacity of electricity generation. The Project Activity is a large hydro power plant, thus similar plants would be hydro power plants with capacity of more than 20 MW[29] that are located in Sumatera Island. The existing large hydroelectric power plants in Sumatera Island, not undertaken as CDM projects, are shown in Table B.5.6 below.

As seen below in Table B.5.6, there are 10 large hydro power plants in Sumatera Island. Further table shows 4 hydro power plants with capacity higher than 150 MW, namely Tangga,Siguragura, Singkarak and Musi power plants, with a comparable scale of electricity generation with the project activity.

Classifying on the basis of the technology, among the four projects, Musi is based on run-of-river technology and is comparable with the Project activity. The other three plants are dam based and hence are not comparable with the project activity. The electricity generation in run of river projects are more affected because of the fluctuation in the river flow as compared to the dam based project.

In addition to the comparison of Musi Power plant and the project activity, Musi power plant is a PLN owned power plant whereas the Project activity is developed by the private Independent Power Producers. As PLN is the state-owned electricity company, projects developed by them are less exposed to the investment risks faced by private sector companies. The PLN owned company are also supported by the government budget and related loans.

Table B.5.7 - Existing Large Hydro Power Stations of Sumatera Island (≥ 20 MW)

Name of power plant[30]	Installed Capacity (MW)	Hydro Technology	Location	Project Owner	Date of commissioning	Grid Connection
Renun	82	Run-of-river	North Sumatera	PLN	Unit 1: 2005 Unit 2: 2006	Yes
Musi	210	Run-of-river	Bengkulu	PLN	2006	Yes

[28] Department of Energy and Mineral Resources (Departemen Energi dan Sumber Daya Mineral) - Indonesian Government (2003), National Energy Policy 2003-2020. Jakarta: Department of Energy and Mineral Resources.

[29] WCD definition for Large Hydro Power Plant

[30] PT PLN Persero Pembangkitan Sumbagsel, Data Unit Pembangkit [Online], Available from: http://pln-kitsbs.co.id/viewpage.php?page_id=144 [Accessed 23 November 2010]

Sipan Sihaporas	67	Dam	North Sumatera	PLN	Unit 1: 2002 Unit 2&3: 2004	Yes
Batutegi	28	Dam	Lampung	PLN	2002	Yes
Way Besai	90	Run-of-river	Lampung	PLN	2001	Yes
Pekanbaru (Koto Panjang)	114	Dam	Riau	PLN	1998	Yes
Singkarak	175	Dam	South Sumatera	PLN	1998	Yes
Maninjau	68	Dam	Riau & West Sumatera	PLN	1983	Yes
Tangga[31]	317	Dam	North Sumatera	Inalum[32] (IPP[32])	1982	Yes
Siguragura[30]	286	Dam	North Sumatera	Inalum[31] (IPP)	1982	Yes
Current Total Capacity of Sumatera Hydroelectric Power Plants (MW)		1,437				

Source: PLN statistic and Local Newspaper

From the above table, the Project Activity is the only large run-of-river hydro power plant that is not owned by the state-owned electricity company (PLN). The Project Activity is the first run-of- river developed by an Independent Power Producer (IPP)[33] in Sumatera island.

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

There are important distinctions between this project and other existing hydroelectric power plants with similar installed capacity in the Sumatera Grid as the Project Activity is an IPP's project that uses run-of-river technology.

Based on the capacity, there are only 4 plants that are of the same scale or bigger than the project activity (i.e. above 150 MW): Tangga, Siguragura, Singkarak and Musi power plants. Of these plants, however, only Musi employs run of river technology and can therefore be considered to adopt the same technology as the project activity. Run of river hydroelectric plants are considered a more environmentally sustainable technology because they are less disruptive to the surrounding area than dam-based projects, produce no greenhouse gas emissions, and utilise an abundant natural resource. Singkarak and Musi power plants were both developed by the state-owned company PLN, which does not face the same barriers as an independent power producer and thus would not be subject to the same investment benchmark, and can call upon the government budget and government supported loans.

The Tangga and Siguragura projects were commissioned in 1982, under completely different economic and developmental conditions. The Project Developer, as a private sector developer, faces greater difficulties accessing finance and possesses a higher degree of liability and difficulties to negotiate and acquire a favourable tariff from the state owned grid company PLN, while previously implemented projects did not face similar constraints as they are heavily linked with and or owned by PLN. Therefore the project cannot be considered common practice.

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

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[31] Badan Pengkajian dan Penerapan Teknologi (BPPT), Direktorat Teknologi Konversi dan Konservasi Energi - Deputi Bidang Teknologi Informasi, Energi, Material dan Lingkungan, Aspek-aspek dalam Desain PLTA Mamberamo (Laporan Teknis)

[32] Inalum is short for PT. Indonesia Asahan Aluminum, a joint venture smelting plant company between Indonesia and Japan

[33] An Independent Power Producer (IPP) is a private sector investor who owns power plants that generate electricity supplied to the grid

B.6. Estimation of emission reductions

B.6.1. Explanation of methodological choices

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In line with ACM0002 Version 17 the methodological steps and choices to determine project emissions, baseline emissions, leakage and emission reductions for the project activity are described below.

Project Emissions

For most renewable energy 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:

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

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)

PE_{FF}

As outlined in the methodology, project emissions from fossil fuel consumption at geothermal and solar thermal power plants shall be accounted for as these projects also use fossil fuel for electricity generation.

Further, the methodology specifies that for all renewable energy power generation project activities, emissions due to the use of fossil fuels for the backup generator can be neglected.

The project activity is a hydro power plant that only uses fossil fuel for the backup generator. As such, project emissions from fossil fuel combustion are not monitored and accounted for.

PE_{GP}

The project activity is not a geothermal power plant and as such PE_{GP} is not applicable.

PH_{HP}

For hydro power project activities that result in new single or multiple reservoirs and hydro power project activities that result in the increase of single or multiple existing reservoirs, project proponents shall account for CH4 and CO2 emissions from the reservoirs. This, however, is not applied for this Project Activity. The project activity is a run-of-river hydro project with a pre-existing natural reservoir (lake) and no additional flooded area. Thus, the power density of the project activity does not need to be considered and therefore, there is no need to account for PE_{HP} for the project activity.

Baseline Emissions

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

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

Where:

Be_y	= Baseline emissions in year *y* (tCO_2e/yr)
$EG_{PJ,y}$	= Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year *y* (MWh/yr)
$EF_{grid,CM,y}$	= Combined margin CO_2 emission factor for grid connected power generation in year *y* calculated using the latest version of the "Tool to calculate the emission factor for an electricity system" (tCO_2/MWh)

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

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

Where:

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

As outlined above, the grid emission factor – the **combined margin** calculated in accordance with the calculated in accordance with Tool to calculate the emission factor for an electricity system has been updated in this PDD based on the data and calculation provided by the Ministry of Mineral and Mineral Resources. Full data sets and calculations are provided to the DOE. The **project electricity system** is the Sumatra grid as published by the DNA. Only grid power plants are included in the calculation. The **Average OM** is selected.

In line with the tool, the **build margin** at the second crediting period has been updated based on the most recent information available on units already built. The units that comprise at least 20% of the system generation, excluding CDM comprises large generation than the 5 most recent power units, and this set does not include units older than 10 years. As such, this is used to calculate the BM.

The **Weighted average CM** is used, and the W_{OM} = 0.25 and W_{BM} = 0.75.

EFgrid,OMsimple,2015 (tCO_2/MWh)	W_{OM}	EFgrid,BM,2015 (tCO_2/MWh)	W_{BM}	EFgrid,CM,2015 (tCO_2/MWh)
0.676	**0.25**	**0.933**	**0.75**	**0.869**

Leakage

According to the methodology, no leakage emissions are considered.

Emission Reductions

Emission reductions are calculated as follows: $ER_y = BE_y – PE_y$

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)

B.6.2. Data and parameters fixed ex ante

(Copy this table for each piece of data or parameter.)

Data / Parameter	$EF_{grid,OM,y}$
Unit	tCO_2/MWh
Description	Operating Margin emission factor of Sumatera
Source of data	ESDM - Kementerian Energi dan Sumber Daya Mineral (Ministry of Energy and Mineral Resources)
Value(s) applied	0.676
Choice of data or Measurement methods and procedures	Calculated in accordance with the Tool to calculate the emission factor for an electricity system
Purpose of data	Calculation of baseline emissions
Additional comment	http://www.djk.esdm.go.id/index.php/layanan-info-pub/2016-01-08-03-54-21/faktor-emisi-pembangkit-listrik At the time of validation, 2015 data are available.

Data / Parameter	$EF_{grid,BM,y}$
Unit	tCO_2/MWh
Description	Build Margin emission factor of Sumatera
Source of data	ESDM - Kementerian Energi dan Sumber Daya Mineral (Ministry of Energy and Mineral Resources)
Value(s) applied	0.933
Choice of data or Measurement methods and procedures	Calculated in accordance with the Tool to calculate the emission factor for an electricity system
Purpose of data	Calculation of baseline emissions

Additional comment	http://www.djk.esdm.go.id/index.php/layanan-info-pub/2016-01-08-03-54-21/faktor-emisi-pembangkit-listrik At the time of validation, 2015 data are available.

Data / Parameter	$W_{OM,}$
Unit	Weight
Description	Weighting of operating margin emissions factor
Source of data	Tool to calculate the emission factor for an electricity system
Value(s) applied	0.25
Choice of data or Measurement methods and procedures	Taken from para 87 of Tool to calculate the emission factor for an Electricity system for second crediting period.
Purpose of data	to calculate the emission factor
Additional comment	As per para 87 of Tool to calculate the emission factor for an Electricity system for second crediting period.

Data / Parameter	$W_{BM,}$
Unit	Weight
Description	Weighting of build margin emissions factor
Source of data	Tool to calculate the emission factor for an electricity system
Value(s) applied	0.75
Choice of data or Measurement methods and procedures	Taken from para 87 of Tool to calculate the emission factor for an Electricity system for second crediting period.
Purpose of data	Calculation of EFgrid,CM
Additional comment	As per para 87 of Tool to calculate the emission factor for an Electricity system for second crediting period.

Data / Parameter	$EF_{grid,CM}$
Unit	tCO_2/MWh
Description	Combined Margin emission factor of Sumatra
Source of data	ESDM - Kementerian Energi dan Sumber Daya Mineral (Ministry of Energy and Mineral Resources)
Value(s) applied	0.869
Choice of data or Measurement methods and procedures	Calculated in accordance with the Tool to calculate the emission factor for an electricity system using the above BM and OM weighting.
Purpose of data	Calculation of baseline emissions
Additional comment	http://www.djk.esdm.go.id/index.php/layanan-info-pub/2016-01-08-03-54-21/faktor-emisi-pembangkit-listrik

B.6.3. Ex ante calculation of emission reductions

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As outlined in Section B.6.1. there are no project leakage emissions from the project activity, and hence emission reductions are equal to baseline emissions.

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

Where:

BE_y = Baseline emissions in year y (tCO_2e/yr)

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

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

For the project Activity, $EG_{PJ,y} = EG_{facility,y}$ = 1,175,000 MWh and $EF_{grid,CM}$ is 0.869

Annual ex-ante emission reductions are thus 1,021,075 tCO_2e

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

Year	**Baseline emissions ($t\ CO_2e$)**	**Project emissions ($t\ CO_2e$)**	**Leakage ($t\ CO_2e$)**	**Emission reductions ($t\ CO_2e$)**
2018	1,021,075	0	0	1,021,075
2019	1,021,075	0	0	1,021,075
2020	1,021,075	0	0	1,021,075
2021	1,021,075	0	0	1,021,075
2022	1,021,075	0	0	1,021,075
2023	1,021,075	0	0	1,021,075
2024	1,021,075	0	0	1,021,075
Total	7,147,525	0	0	7,147,525
Total number of crediting years	7			

Annual average over the crediting period	1,021,075	0	0	1,021,075

B.7. Monitoring plan

B.7.1. Data and parameters to be monitored

Data/Parameter	***$EG_{facility,y}$***
Data unit	MWh/year
Description	Quantity of net electricity generation supplied by the project plant to the grid in year *y*.
Source of data	Measured at transaction point at the project activity site (in Asahan 1 switchyard)
Value(s) applied	1,175,000. (estimated)
Measurement methods and procedures	Electricity will be measured with two way electricity meters in the presence of Project Developer and PLN. Data will be recorded monthly and will be cross-checked with the invoices.
Monitoring frequency	Monthly
QA/QC procedures	Meters will be calibrated periodically and inspection will be performed by PLN as deemed necessary according to the agreed PPA (Appendix K article 4.2.5. Re-testing and re-calibration of each Metering System shall be performed annually upon written notification of PLN to Seller”). The metering system shall include sealable primary and check digital type meter, in which the check meter measurement shall be used when the measurement of primary meter does not satisfy the applicable accuracy standard, as according to article 4.2.8.
Purpose of data	Baseline emissions calculation
Additional comment	There are two primary meters and two check meters (one each for each turbine).

B.7.2. Sampling plan

>>
Not Applicable

B.7.3. Other elements of monitoring plan

>>
This section details the steps taken to monitor on a regular basis the GHG emissions reductions from the Asahan-1 Hydroelectric Power Plant Project in Indonesia. The Monitoring Plan for this project has been developed to ensure that from the start, the project is well organised in terms of the collection and archiving of complete and reliable data.

The monitoring of this type of project consists of metering the electricity generated by the renewable technology. Below is the description of monitoring procedures for data measurement, quality assurance and quality control. All data collected as part of monitoring will be archived electronically and be kept at least for 2 years after the end of the crediting period.

PLN, as the state-owned company that owns the Grid to which the Project Developer sends its electricity to, is responsible for maintaining sound electricity monitoring standards for grid connected plants. The monitoring plan of the project will follow the PLN system of measuring the electricity sent to the Grid.

Data will be collected by site operators who are under the supervision of the CDM Manager. Onsite net export data is collected as outlined below on a monthly basis in hardcopy format and archived electronically.

Metering of Electricity Supplied to the Grid

The main electricity meter for establishing the electricity delivered to the grid will be installed at the project site using a Metering System that is approved by PLN, as defined in Appendix K of the PPA. Each Metering System shall include sealable primary and check digital type meters each having two pulse outputs. This primary electricity meter provides the main data for CER measurement, thus it will be the key part of the verification process. The check meter measurement shall be used when the measurement of primary meter does not satisfy the applicable accuracy standard. In addition, as according to Appendix K of the PPA, if any failure happened with both primary and check meters, then any remaining metering equipments which is still accurate and the records for the relevant period of the data processor for the power plant shall be taken into account. There are two primary meters and two check meters (one each for each turbine).

Quality Control and Quality Assurance

Quality control and quality assurance procedures will guarantee the quality of data collected. The electricity meter(s) will undergo periodic calibration throughout the lifetime of the Project Activity in accordance with the latest editions of IEC standards and in conformance with related manufacturer's recommendation, as stated in Appendix K of PPA. Re-testing and re-calibration of each metering system shall be performed annually upon written notification of PLN to Project Developer. Additional testing and re- calibration of a relevant metering system or any of its components shall be performed if any of its primary and check meters show differences of more than 0.25% in transferred energy. Moreover, meters are maintained using genuine spare parts. Documents detailing these procedures will be available during the verification.

SECTION C. Start date, crediting period type and duration

C.1. Start date of project activity

>>

24/07/2006 (The date of the EPC contract signing, which is also the financial closure as the EPC contractor is the one giving loan to the project)

C.2. Expected operational lifetime of project activity

>>

30 years[34]

C.3. Crediting period of project activity

C.3.1. Type of crediting period

>>

Renewable. This PDD is for the second crediting period.

C.3.2. Start date of crediting period

>>

1 March 2018

[34] Based on Project Operational Statement Letter

C.3.3. Duration of crediting period

>>
7 years

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

>>
Based on the letter issued by the Department of Mining and Energy, Directorate General of Electricity and Energy Development, the Project Activity was not required to complete an Environmental Impact Assessment (AMDAL [35]). However, it is still required to submit an Environmental Management (UKL) and Environmental Monitoring (UPL) Procedure to be approved and fulfilled. The Project Activity will also need to comply with the procedure by submitting a periodic report.

D.2. Environmental impact assessment

>>
The Project is expected to deliver an overall positive sustainable impact and development on the local and global environment as mitigation controls are planned thoroughly and it is becoming an integral part of the construction and UKL/UPL processes. All negative environmental impacts are subject to mitigation measures as described below.

Table D.1 Summary of Environmental Management Procedure findings

Identified Impacts	Management Procedures
Pre-Construction phase	
Survey	
Perception and social unrest	Informing about the goal, benefits and activity plan; Involving local man power
Land preparation	
Loss of jobs	Informing about compensation of land, tress, or building
Changes in land use increase of income	Informing about land acquisition procedures
Land speculation	Informing about managing compensation money
Construction phase	
Land Clearing and Consolidation	
Reduction on plant and wild animal population	Replanting on open land
Dust	Watering regularly
Noise	Using earplug
Sedimentation	Lessen land clearing
Heavy equipment mobilization	
Traffic accident	Placing traffic sign
Road quality decrease	Improving road facility
Dust	Watering regularly
Noise	Using earplug
Infrastructure development	
Dust	Watering regularly

[35] AMDAL is Analisa Mengenai Dampak Lingkungan (EIA) where its application for different projects are managed by the Ministry of Environment

Noise	Using earplug
Sedimentation	Drainage system construction sediment pond
Main building construction	
Dust	Watering regularly
Noise	Using earplug
Landslide and sedimentation	Sediment pond
Vegetation and animal extinction	Replanting in open land
Income increases	Directing on work characteristic
Changes in soil surface	Regulating on implementation
Manpower recruitment and reduction	
Changes of jobs	Explain to the applicant about possibility of social unrest, temporary work
Income increases	Local man power utilization
Restlessness because of losing jobs	Introducing local culture to the workers
Operation phase	
Generating system operation	
Job opportunity	Improving economic condition
Life quality increase	Informing about electricity benefits
Aquatic weed	Clearing the weeds
Solid waste	Waste collection
Generating system maintenance	
Manpower absorption	Absorption of local man power
Post operation phase	
Former building arrangement	
Dust	Watering regularly
Noise	Using earplug
Land use	Determining land status instantly
Job opportunity	Informing about temporary income
Land reclamation	
Plant re-growth	Replanting properly
Job opportunity	Employing local man power

SECTION E. Local stakeholder consultation

E.1. Modalities for local stakeholder consultation

>>

A stakeholder consultation forum was hosted and organized by Project Developer, held in the Multi-Purpose Hall of PT. Bajradaya Sentranusa (at the project site), on 18th March 2009. The meeting was done from 09.30 am to 13.00 pm; with 55 participants representing the local stakeholders attended the meeting. The local stakeholders were invited by the Project Developer through invitation letters. Please see Table E.1 for detail meeting agenda.

Table E.1 Meeting Agenda

09.30 – 10.00	Participants Registering
10.00 – 10.15	Introduction by Bambang Suharsono, *(Technical Manager of Asahan I Hydroelectric Power Plant)*
10.15 – 10.30	Welcoming speech by Frans Wijaya

(Project Director of Asahan I Hydroelectric Power Plant)

10.30 – 10.45	Welcoming speech by Bambang P. Hidayat *(Deputy Director of PT. BDSN Jakarta)*
10.45 – 11.00	Welcoming speech of Mangara Butarbutar *(Head of Porsea District)*
11.00 – 11.30	Brief Description of Asahan 1 Hydroelectric Power Plant by Bambang Suharsono *(Technical Manager of Asahan I Hydroelectric Power Plant)*
11.30 – 12.15	Presentation of Climate Change and CDM by Muayat Ali Muhshi, *(Facilitator CDM from PT. PEACE Jakarta)*
12.15 – 12.45	Discussion *(Question and Answer)*
12.45 – 13.00	Lunch and closing

The Project Director, Mr. Frans Wijaya, from Asahan 1 Project and Deputy Director, Mr. Bambang P. Hidayat from Jakarta opened the local Stake Holder and Consultation by welcoming all Participants and followed up by an opening speech of the Head of Porsea Districts as a Local Representative of the Goverment.

Muayat Ali Muhshi of PEACE, a consultant for stakeholder consultation to PT EcoSecurities Indonesia delivered his presentation on Climate Change and Clean Development Mechanism. The structure of the presentation is as follow:

a. Climate Change and its global impact
b. Impact to Indonesia
c. UNFCCC and Kyoto Protocol
d. Clean Development Mechanism
e. Asahan I Hydroelectric Power Plant as CDM Project.

Mr Bambang Suharsono, the Technical Manager of Asahan I Project delivered his brief presentation on the project description and progress of Asahan I Hydroelectric Power Project.

The Q&As session started after all presentations were delivered and The Organizer requested to all participants to forward their inquiries, comments and suggestions limited to the project development and implementation only. The Q&A's session started at 12.15 pm and ended successfully leaving all participants contently informed about the project. The session is closed with an affable luncheon provided by the Project Developer.

E.2. Summary of comments received

>>

In general, all participants in the forum support the implementation of Asahan 1 Hydroelectric Power Plant to fulfil the electricity demand of North Sumatera in particular and the whole Sumatera in general. The Participants have high expectation that Asahan I will bring in significant benefits to the local community, particularly on the benefit of increasing the level of their living standard and employment

There are three categories of comments received from the stakeholder, they are as the following: (1) expressing commitment to support the Asahan 1 Hydroelectric Power Plant; (2) community

development programs to local economic, employment and environmental (3) environmental impact of the project. See below for detail comments:

a. Q : Women Representation From Tangga Batu I,

She commented about how these kinds of activities have often been done before and informed about a previous program of household garbage processing system; however, there is not any follow-up of it. She suggested to the Project Developer that they can develop and follow up those kinds of program. Furthermore, she would like to get more information about implementation of Clean Development Mechanism for local condition.

Answer (Bambang Suharsono):
Comments, suggestions and hopes from the stakeholders will be considered for the next programs of Project Developer.

Answer (Muayat):
There are many activities that could be developed in CDM, such as energy saving; fuel switch (hydro power, solar power, wind power, sea wave power, etc.); reforestation; energy efficiency in factory; and garbage or waste processing. For local condition, several types of activities could be planned for the environment awareness: garbage processing and conservation of water catchment area.

b. Q : Local inhabitant From Simangkok

He expressed his gratitude to the Project Developer for implementing the hydroelectric project and explained some other impacts of the project to local environment. It is causing deterioration of several public utilities such as roadway to village, the graves and the house building. He hoped that the company can use local employee to work in the project and cooperate more with the community.

Answer (Frans Wijaya):
Project management realized the positive and negative impact of the project and efforts have been done continuously to minimize the negative impact. This forum is the place to discuss a mutual understanding between the project and local community, in which the project existence is part of the community as well.

c. Q: Local CSO

He requested some explanation from the Project Developer about the company program for household garbage/waste process and the implementation of community development program of the project for local community. He also requested the detail information about the importance of this forum for CDM Project

Answer (Frans Wijaya):
Community Development Program has been implemented at Ambar Halim Village. The program is to build canal and piping for fresh water supply to houses. CDM project is aiming to reduce the carbon emission as part of the private sector contribution for environmentally sound development.

Muayat (PEACE):
CDM Project required participation from local stakeholders through stakeholder consultation during the planning of Project Activity. For this project, the consultation is done through a meeting in which

the process is made as transparent and as objective as possible to gather the community's opinion on the project.

d. Q: Mangara Butar Butar, Head of Porsea District

He emphasized that the Project Developer is giving effort to provide electricity to Ambar Halim village through the Grid as part of their Corporate Social Responsibility (CSR).

E.3. Consideration of comments received

>>
The comments received were either questions concerning the project, or broad statements in support of the activity, therefore there was no need to amend the project in order to take into account negative comments.

SECTION F. Approval and authorization

>>
The letters of approval and authorisation from the Republic of Indonesia were granted on 21 January 2010.

Appendix 1. Contact information of project participants

Organization name	PT Bajradaya Sentranusa
Country	Indonesia
Address	Jl. Dharmawangsa VII no. 7, Kebayoran Baru, Jakarta 12160
Telephone	+62 21 7260502
Fax	+62 21 7260584
E-mail	ana@bajradaya.co.id
Website	
Contact person	Ms Hariati Oktiviana

Appendix 2. Affirmation regarding public funding

No public funding is being provided for this project.

Appendix 3. Applicability of methodologies and standardized baselines

Please refer to the Section B.1 of the PDD.

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

The data and calculations below outline the official ex-ante combined margin provided by the Ministry of Energy and Mineral Resources and endorsed by the Indonesia DNA. These figures calculate the OM and BM and a combined margin based on a 0.5:0.5 weighting of BM and CM. As such, the combined margin outlined in Section B.6 of this PDD and applicable to the project activity in its second crediting period differs as a 0.75:0.25 BM:OM ratio is required in the second crediting period.

Operating Margin	Build Margin	OM:BM Weighting	Combined Margin
0.676	0.933	0.5:0.5	0.805
0.676	0.933	0.25:0.75	0.869

The data are **2015** which are the latest available at the time of validation. In comparison to the figures applicable during the first crediting period (based on 2007 data) the average operating margin has declined from 0.906 tCO2e/MWh to 0.676 tCO2e/MWh as a larger proportion of generation has originated from hydro and gas plants whilst the build margin has increased from 0.581 tCO2e/MWh to 0.933 tCO2e/MWh as new construction has focussed on coal, oil and gas generation sources.

KEMENTERIAN ENERGI DAN SUMBER DAYA MINERAL
DIREKTORAT JENDERAL KETENAGALISTRIKAN

Perhitungan Faktor Emisi Ex-ante 2015
Sistem Inter Koneksi Sumatera

1. Identifikasi sistem interkoneksi tenaga listrik terkait
Data yang dibutuhkan :

Tahun
2015

2. Mengikutsertakan pembangkit *on-grid* dan *off-grid* dalam perhitungan
Opsi I : Pembangkit yang terhubung dengan sistem interkoneksi tenaga listrik *(on-grid)* diikutsertakan dalam perhitungan
~~Opsi II : Pembangkit *on-grid* dan pembangkit yang tidak terhubung dengan sistem interkoneksi tenaga listrik *(off-grid)* diikutsertakan dalam perhitungan~~

3. Menentukan metode *Operating Margin* (OM)

a. Simple OM	x
b. Simple adjusted OM	x
c. Dispatch data analysis OM	x
d. Average OM	√

4. Menghitung faktor emisi OM sesuai dengan metode yang telah ditentukan

$$EF_{grid,OM\text{-}average,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Average OM

Tahun	$EF_{grid,AverageOM,2015}$ (tCO_2/MWh)	$EF_{grid,AverageOM,2015}$ (tCO_2/MWh)
2013	**0.589**	**0.676**
2014	**0.661**	
2015	**0.778**	

5. Identifikasi kelompok unit pembangkit yang termasuk dalam *Build Margin* (BM)
~~Kelompok I : Lima pembangkit terakhir yang telah dibangun dan beroperasi yang menyalurkan energi listrik ke sistem interkoneksi tenaga listrik~~

Unit Pembangkit	Tahun Operasi	*Power Generation Nett* - $EG_{m,2015}$ (MWh)
PLTU Banjar Sari #2 (PT. Bukit Pembangkit Innovative)	2015	231,811.00
PLTU Sumsel 5 (PT. DSSP Power)	2015	9,999.00
PLTU Keban Agung (PT. Priamanaya Energi)	2015	73,258.00
PLTU Unit 1 (Pangkalan Susu)	2015	473,697.48
PLTU Unit 2 (Pangkalan Susu)	2015	581,499.90

Total energi listrik tersalur oleh unit pembangkit	1,370,265.38	MWh
Total energi listrik tersalur ke sistem interkoneksi	30,341,574.22	MWh
Persentase	4.52%	

Kelompok II : Sejumlah pembangkit terakhir dibangun yang menyalurkan energi listrik sebesar ≥ 20% total yang disalurkan ke sistem interkoneksi tenaga listrik

Unit Pembangkit	Tahun Operasi	*Power Generation Nett* - $EG_{m,2015}$ (MWh)
PLTD PT Berkat Bima Sentana / PLTD Sewa 120 MW di Belawan (Sektor Medan)	2013	520,298.00
PLTD PT Bima Golden Powerindo, Glugur (Sektor Medan)	2013	55,560.00
PLTD PT Kurnia Purnama Tama, Paya Pasir (Sektor Medan)	2013	249,003.00
PLTD PT Prastiwahyu Trimitra Engineering, Kualanamu (Sektor Medan)	2013	99,062.00
PLTD PT Prastiwahyu Trimitra Engineering, Tamora (Sektor Medan)	2013	75,522.00
PLTMG PT PJBS TL. Lembu (Sektor Pekanbaru)	2013	205,313.00
PLTMG Navigat Balai Pungut / PLTMG 40 MW Balai Pungut (Sektor Pekanbaru)	2013	326,105.00
PLTMG Hutan Alam Teluk Lembu (Sektor Pekanbaru)	2013	387,966.00
PLTMG Sungai Gelam (CNG) #1	2013	12,285.96
PLTMG Sungai Gelam (CNG) #2	2013	8,980.38
PLTMG Sungai Gelam (CNG) #3	2013	6,217.46
PLTMG Sungai Gelam (CNG) #4	2013	8,031.84
PLTMG Sungai Gelam (CNG) #5	2013	6,181.38
PLTMG Sungai Gelam (CNG) #6	2013	3,985.86
PLTMG Sungai Gelam (CNG) #7	2013	8,053.26
PLTMG Sungai Gelam (CNG) #8	2013	9,478.38
PLTMG Sungai Gelam (CNG) #9	2013	7,226.85
PLTMG Sungai Gelam (CNG) #10	2013	8,126.83
PLTMG Sungai Gelam (CNG) #11	2013	11,310.79
PLTG LM 2500 Talang Duku #3 (Sektor Keramasan)	2013	107,397.00
PLTD GI PIP / PLTD Sewatama (Sektor Ombilin)	2013	11,169.41
~~PLTBm PT Rimba Palma Unit 1~~	~~2013~~	~~55,000.00~~
PLTU Tarahan #5 /PLTU Sebalang #1	2014	33,417.22
PLTU Naganraya 1	2014	436,628.34
PLTU Naganraya 2	2014	262,565.22
PLTD PT Bima Golden Powerindo GI Langsa (Sektor Naganraya)	2014	24,736.00
PLTD GI Tualang Cut Baru (Sektor Naganraya)	2014	44,187.00
~~PLTA Tes #7~~	~~2014~~	~~9,859.00~~
PLTGU Keramasan #1	2014	292,510.00
PLTGU Keramasan #2	2014	270,607.00
PLTU Teluk Sirih #1	2014	468,924.93
PLTU Teluk Sirih #2	2014	472,666.23
PLTMG Payo Selincah	2014	182,756.00
~~PLTA Asahan II (PT Inalum)~~	~~2014~~	~~463,623.00~~
~~PLTBm PT Harkat Sejahtera Unit 1~~	~~2015~~	~~55,776.00~~
PLTU Banjar Sari #1 (PT. Bukit Pembangkit Innovative)	2015	231,811.00
PLTU Banjar Sari #2 (PT. Bukit Pembangkit Innovative)	2015	231,811.00
PLTU Sumsel 5 (PT. DSSP Power)	2015	9,999.00
PLTU Keban Agung (PT. Priamanaya Energi)	2015	73,258.00
PLTU Unit 1 (Pangkalan Susu)	2015	473,697.48
PLTU Unit 2 (Pangkalan Susu)	2015	581,499.90

Total energi listrik tersalur oleh unit pembangkit	6,218,348.72	MWh
Total energi listrik tersalur ke sistem interkoneksi	30,341,574.22	MWh
Persentase	20.49%	

6. Menghitung faktor emisi BM

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Unit Pembangkit	***Power Generation Nett*** **- $EG_{m,2015}$ (MWh)**	**$EG_{m,2015}$ x $EF_{EL,m,2015}$ (tCO_2)**	**$EF_{grid,BM,2015}$ (tCO_2/MWh)**
PLTD PT Berkat Bima Sentana / PLTD Sewa 120 MW di Belawan (Sektor Medan)	520,298.00	373,359.09	**0.933**
PLTD PT Bima Golden Powerindo, Glugur (Sektor Medan)	55,560.00	41,371.72	
PLTD PT Kurnia Purnama Tama, Paya Pasir (Sektor Medan)	249,003.00	197,563.34	
PLTD PT Prastiwahyu Trimitra Engineering, Kualanamu (Sektor Medan)	99,062.00	65,617.52	
PLTD PT Prastiwahyu Trimitra Engineering, Tamora (Sektor Medan)	75,522.00	49,330.67	
PLTMG PT PJBS TL. Lembu (Sektor Pekanbaru)	205,313.00	111,024.17	
PLTMG Navigat Balai Pungut / PLTMG 40 MW Balai Pungut (Sektor Pekanbaru)	326,105.00	180,099.01	
PLTMG Hutan Alam Teluk Lembu (Sektor Pekanbaru)	387,966.00	188,136.41	
PLTMG Sungai Gelam (CNG) #1	12,285.96	6,844.43	
PLTMG Sungai Gelam (CNG) #2	8,980.38	4,848.23	
PLTMG Sungai Gelam (CNG) #3	6,217.46	3,348.67	
PLTMG Sungai Gelam (CNG) #4	8,031.84	4,309.24	
PLTMG Sungai Gelam (CNG) #5	6,181.38	3,430.00	
PLTMG Sungai Gelam (CNG) #6	3,985.86	2,085.09	
PLTMG Sungai Gelam (CNG) #7	8,053.26	4,323.12	
PLTMG Sungai Gelam (CNG) #8	9,478.38	5,260.67	
PLTMG Sungai Gelam (CNG) #9	7,226.85	3,914.71	
PLTMG Sungai Gelam (CNG) #10	8,126.83	4,462.27	
PLTMG Sungai Gelam (CNG) #11	11,310.79	5,962.39	
PLTG LM 2500 Talang Duku #3 (Sektor Keramasan)	107,397.00	69,491.30	
PLTD GI PIP / PLTD Sewatama (Sektor Ombilin)	11,169.41	8,326.84	
~~PLTBm PT Rimba Palma Unit 1~~	~~55,000.00~~		
PLTU Tarahan #5 /PLTU Sebalang #1	33,417.22	56,474.88	
PLTU Naganraya 1	436,628.34	520,053.25	
PLTU Naganraya 2	262,565.22	342,250.48	
PLTD PT Bima Golden Powerindo GI Langsa (Sektor Naganraya)	24,736.00	15,563.61	
PLTD GI Tualang Cut Baru (Sektor Naganraya)	44,187.00	28,450.28	
~~PLTA Tes #7~~	~~9,859.00~~		
PLTGU Keramasan #1	292,510.00	147,463.12	
PLTGU Keramasan #2	270,607.00	135,414.91	
PLTU Teluk Sirih #1	468,924.93	561,209.08	
PLTU Teluk Sirih #2	472,666.23	590,995.64	
PLTMG Payo Selincah	182,756.00	83,047.75	
~~PLTA Asahan II (PT Inalum)~~	~~463,623.00~~		
~~PLTBm PT Harkat Sejahtera Unit 1~~	~~55,776.00~~		
PLTU Banjar Sari #1 (PT. Bukit Pembangkit Innovative)	231,811.00	346,948.52	
PLTU Banjar Sari #2 (PT. Bukit Pembangkit Innovative)	231,811.00	346,948.52	
PLTU Sumsel 5 (PT. DSSP Power)	9,999.00	24,299.41	
PLTU Keban Agung (PT. Priamanaya Energi)	73,258.00	121,136.73	
PLTU Unit 1 (Pangkalan Susu)	473,697.48	509,280.35	
PLTU Unit 2 (Pangkalan Susu)	581,499.90	639,851.97	

7. Menghitung faktor emisi *Combined Margin* (CM)

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

$EF_{grid,AverageOM,2015}$ (tCO_2/MWh)	**W_{OM} (%)**	**$EF_{grid,BM,2015}$ (tCO_2/MWh)**	**W_{BM} (%)**	**$EF_{grid,CM,2015}$ (tCO_2/MWh)**
0.676	**0.5**	**0.933**	**0.5**	**0.805**

Appendix 5. Further background information on monitoring plan

Please refer to the Section B.7 of the PDD.

Appendix 6. Summary report of comments received from local stakeholders

Please refer to the Section E.2 of the PDD.

Appendix 7. Summary of post-registration changes

This PDD for the second crediting period contains three post-registration changes to the PDD for the first crediting period. These changes are outlined below:

a) The calibration of the electricity meters will be performed annually. In the registered PDD applicable to the first crediting period, the calibration frequency was set to performed semi-annually.

- The revised calibration frequency for the electricity meters brings calibration in line with manufacturer's specifications.

b) The monitoring parameter FCy: Quantity of fuel combusted in the generator during the year y is not considered for the project activity.

- This revision is in line with Paras 36 and 38 of the applied methodology. These state that for most renewable energy power generation project activities, PEy= 0 and that for all renewable energy power generation project activities, emissions due to the use of fossil fuels for the backup generator can be neglected.

- Under the project activity, the only use of any fossil fuels will be for the backup generator.

c) EGimport,y: Quantity of electricity imported from the grid in year y is not considered under monitoring parameter.

- The electricity meters installed for the monitoring of the electricity generation measures both the export and import of electricity and therefore directly provides a net export figure which is used in the calculation of emissions reductions.

- Net electricity supplied to grid is measured by Meter 1 and Meter 2 installed in 275kV switchyard and during the first crediting period the electricity imported was measured by Meter 3. This meter and connection was discontinued by PLN in July 2015.

As detailed, all of the above changes are fully in compliance with the applied methodology and thus do not have any impact on the applicability of the methodology. Moreover, the changes do not impact the accuracy and completeness of the monitoring procedure.

In addition to the above, the following post-registration change was approved during the first crediting period.

PRC Ref: PRC-4118-002
Approved 10 February 2015

B. Corrections

B.1 Description of corrections

During the site visit of the monitoring period 1 March 2011 to 31 May 2012, DNV has verified through a visual inspection of the turbine and generator nameplates the following:

- The rated speed for the turbine is 300 rpm as verified against the turbine's nameplates whereas the registered PDD indicates 273 rpm.

- The rated current for the generator is 4183.7A as verified against the generators' nameplates whereas the registered PDD indicates 4 184 A.

The correct rated speed for the turbine and rated current for the generator were properly corrected in the revised PDD in accordance with DNV's observations during the site visit and nameplates of the turbine and generator.

…

Document information

Version	*Date*	*Description*
10.1	28 June 2017	Revision to make editorial improvement.
10.0	7 June 2017	Revision to: • Improve consistency with the "CDM project standard for project activities" and with the PoA-DD and CPA-DD forms; • Make editorial improvement.
09.0	24 May 2017	Revision to: • Ensure consistency with the "CDM project standard for project activities" (CDM-EB93-A04-STAN) (version 01.0); • Incorporate the "Project design document form for small-scale CDM project activities" (CDM-SSC-PDD-FORM); • Make editorial improvement.
08.0	22 July 2016	EB 90, Annex 1 Revision to include provisions related to automatically additional project activities.
07.0	15 April 2016	Revision to ensure consistency with the "Standard: Applicability of sectoral scopes" (CDM-EB88-A04-STAN) (version 01.0).
06.0	9 March 2015	Revision to: • Include provisions related to statement on erroneous inclusion of a CPA; • Include provisions related to delayed submission of a monitoring plan; • Provisions related to local stakeholder consultation; • Provisions related to the Host Party; • Make editorial improvement.

Version	*Date*	*Description*
05.0	25 June 2014	Revision to: • Include the Attachment: Instructions for filling out the project design document form for CDM project activities (these instructions supersede the "Guidelines for completing the project design document form" (Version 01.0)); • Include provisions related to standardized baselines; • Add contact information on a responsible person(s)/ entity(ies) for the application of the methodology (ies) to the project activity in B.7.4 and Appendix 1; • Change the reference number from F-CDM-PDD to CDM-PDD-FORM; • Make editorial improvement.
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	13 March 2012	Revision required to ensure consistency with the "Guidelines for completing the project design document form for CDM project activities" (EB 66, Annex 8).
03.0	26 July 2006	EB 25, Annex 15
02.0	14 June 2004	EB 14, Annex 06b
01.0	03 August 2002	EB 05, Paragraph 12 Initial adoption.

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