CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-SSC-PDD)
Version 03 - in effect as of: 22 December 2006

CONTENTS

Annexes

Revision history of this document

Version Number	Date	Description and reason of revision
01	21 January 2003	Initial adoption
02	8 July 2005	• The Board agreed to revise the CDM SSC PDD to reflect guidance and clarifications provided by the Board since version 01 of this document. • As a consequence, the guidelines for completing CDM SSC PDD have been revised accordingly to version 2. The latest version can be found at <http://cdm.unfccc.int/Reference/Documents>.
03	22 December 2006	• The Board agreed to revise the CDM project design document for small-scale activities (CDM-SSC-PDD), taking into account CDM-PDD and CDM-NM.

SECTION A. General description of small-scale project activity

A.1 Title of the small-scale project activity:

Title	Maesod Wastewater Treatment and Biogas Utilisation Project
Version	04
Date	20/01/2012

A.2. Description of the small-scale project activity:

The Maesod Wastewater Treatment and Biogas Utilisation Project (hereafter referred to as the Project) implemented by Maesod Biogas Co., Ltd (MBG) in the north of Thailand. It involves recovery of biogas from the anaerobic digestion of the wastewater released from tapioca starch processing plant using Upflow Anaerobic Sludge Blanket technology (UASB) biogas reactor.

The project activity is implemented in a Greenfield location. In the baseline scenario, the wastewater from the starch factory would have been treated through a series of deep open anaerobic lagoons. The open lagoons are the best available low cost option for wastewater treatment which is also in compliance with the environmental regulations. In the project activity, the wastewater will be treated in UASB and biogas will be recovered. The recovered biogas will be used as fuel in a thermal oil boiler to generate heat for the starch drying process and in a 952KW_{el} gas engine to generate electricity. The electricity generated (about 938kW) will be fed to the Thai national grid. In the case of emergencies or surplus, biogas will be flared using the closed flare system. The starch factory started operation on 11th May 2010.

The recovered biogas contains methane which is a greenhouse gas. In the absence of the project activity, the wastewater treatment system (open lagoons) in the baseline would have released methane to atmosphere and thereby contributing to global warming. Furthermore, the biogas utilised in the boiler replaces heavy fuel oil (fossil fuel). The gas engine using biogas will generate electricity which will displace electricity generated in the grid which is largely based on fossil fuel based power plants[1]. The implementation of the project activity therefore significantly contributes in the reduction of GHG emissions.

Sustainable Development Benefits of the Project
The project activity has received the host country approvals (HCA) from the Thai DNA, from Swiss DNA and from the Swedish DNA. The HCA indicates that the project activity contributes to the sustainable development of the host country. Furthermore, Thai DNA[2] has four major groups in the sustainable development (SD) criteria evaluation and these are indicated and explained below:

Natural Resources and Environment Indicators

- The project activity reduces greenhouse gas emissions through the methane avoidance from anaerobic open lagoon system and the carbon dioxide emissions from electricity generation in the grid and thermal energy generation in the thermal boilers using fossil fuels. The project activity will utilize biogas (a renewable fuel for energy generation).

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[1] http://prinfo.egat.co.th/report/annual_report/annual2009/annual2009eng/pdf/annual2009en_p86.pdf

[2] http://www.tgo.or.th/english/index.php?option=com_content&task=view&id=15&Itemid=1

- The project activity reduces offensive odors which would have occurred if the wastewater was treated in the open lagoons;
- The project activity will reduce air pollution by regularly monitoring stack emissions
- The project activity also introduces a technologically advanced method (UASB) of wastewater treatment compared to the baseline;
- The project activity will recycle water thereby contributing to water conservation.

Social Indicators

- The project activity invited local people to provide comments[3] on the project. This ensured participation from the local public and provided opportunity to understand the technology and benefits resulting from the project;
- Project owner will support local social and cultural events in the form of financial contributions;
- The project owner will also support programs for local community health.

Development and/or technology transfer indicators

- The project activity contributes significantly to technology development and transfer within and to the host country. The UASB system is supplied by Papop Co,Ltd., a local technology provider. The gas engine is manufactured by a Spanish manufacturer (Guascor).
- The technology suppliers will provide necessary training for the operation and maintenance of the equipments in the project activity which will further enhance the skill set of the local employees.
- The capacity of the employees will also increase by learning/adopting good practices for monitoring and data storage due to the stringent CDM monitoring requirements.

Economic indicators

- The project activity leads to the utilization of renewable energy and contributes thereby to energy security and independence in the host country.
- The project activity increases the employment opportunities for the local people by setting up an industrial unit in the area. This will directly promote other related income generation sources like local suppliers, manufacturers, small shop owners etc.
- The project activity contributed to the employment of local people both in the skilled and semi-skilled category during the construction phase. Further, the project activity also generates direct permanent employment opportunities[4] for at least six people.

A.3. Project participants:

Name of Party involved (*) (host) indicate a host party	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Thailand (host)	Private entity: Maesod Biogas Company Limited	No
Switzerland	Private entity: Swiss Carbon Assets Ltd.	No

[3] Please refer to section E for more details.

[4] Please refer to section B.7.2 for more details.

Sweden	Public entity: Swedish Energy Agency	No
(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.		

A.4. Technical description of the small-scale project activity:

A.4.1. Location of the small-scale project activity:

A.4.1.1. Host Party(ies):

Thailand

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

Tak

A.4.1.3. City/Town/Community etc:

192 Moo 8, Maekasa, Maesod District

A.4.1.4. Details of physical location, including information allowing the unique identification of this small-scale project activity :

The proposed project activity is located in the Maesod district, Tak province, Thailand. It is situated at about 500 km north of Bangkok, in the north of Thailand.

The address of the project activity is:
Maesod Biogas Co. Ltd
Moo 8, Maesod – Maeramad road
Maekasa sub-district
Maesod District,
Tak Province – 63110
Thailand

The exact location of the plant[5] is 16°51’22.49″ N, 98°35’19.29″ E.

[5] By Google Earth.

A map indicating the location of the project is provided in Figure 1

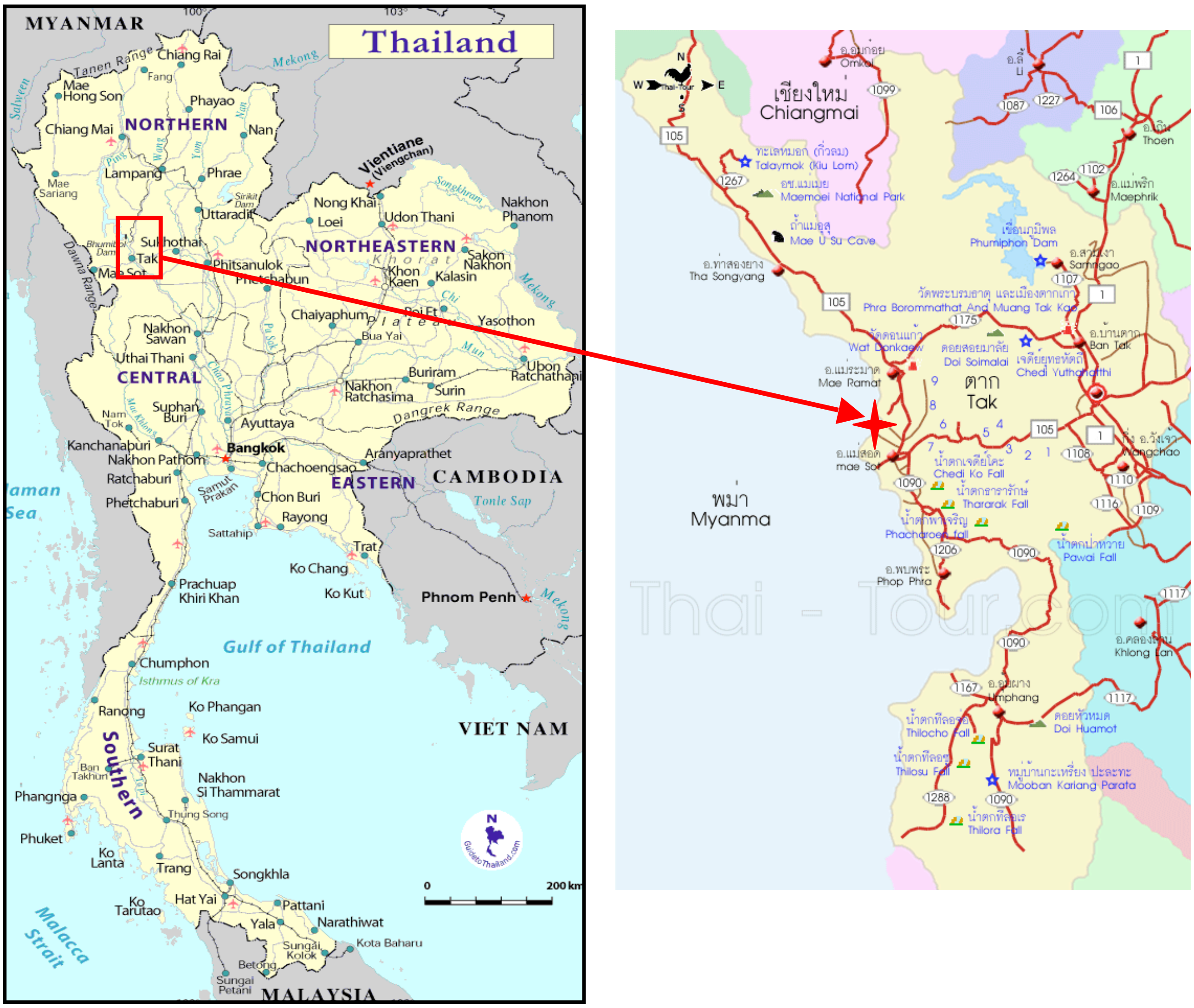

Figure 1. Location of the project activity ( )

A.4.2. Type and category(ies) and technology/measure of the small-scale project activity:

Categories of project activity:
According to Appendix B to the "Simplified Modalities and Procedures for Small-Scale CDM Project Activities", the project type and categories are as follows:

Methane avoidance component:

Type III:	Other project activities
Category M:	Methane recovery

Sectoral Scope 13: Waste handling and disposal

Electricity generation component:

Type I: Renewable energy projects
Category D: Electricity generation for a system
Sectoral Scope 1: Energy industries (renewable /non-renewable sources)

Heat generation component:

Type I: Renewable energy projects
Category C: Thermal energy for the user
Sectoral Scope 1: Energy industries (renewable /non-renewable sources)

Technology to be employed by the project activity

The project activity is implemented next to a new starch factory to treat the wastewater generated by the factory. The starch factory has an installed capacity of about 200 tonnes per day. As per the operation licence, the starch factory started operation on 11th May 2010. The wastewater is generated from separator in the starch factory and from the cassava washing process. The starch factory and the biogas plant (the project) are located adjacent to each other. The exact location is provided in section A.4.1.4.

Anaerobic treatment system

In the UASB, the wastewater rises through an expanded bed of anaerobic active methanogenic sludge (the so called "sludge blanket") undergoing an anaerobic biological process, where organic matter is converted into biogas and sludge. An internal device at the top of the reactor separates the mixed liquor into clarified wastewater, biogas and sludge. With an average inlet COD of 15,053 mg/l[6] and a COD removal efficiency of around 95%[7], the production of biogas is expected at 28,000 m3 per day (with the methane percentage being around 65%).

Biogas handling and use

The project activity plans to utilise the biogas for thermal and power generation purposes. A part of the biogas captured will be combusted in a thermal oil boiler for providing thermal energy to the starch drying process. The thermal oil boiler is designed with a rated capacity of 3,500,000 kcal/h. The remaining biogas will be used for electricity generation in a gas engine of 952kWe rated capacity. The biogas will be first treated to reduce the sulphur content by the H_2S cleaning system (Bio-Scrubber). The electricity generated will be exported to the grid. In the case of emergencies or surplus, biogas will be flared by enclosed flaring system having a capacity of 500m3/hour.

Technology transfer and training:

The UASB system is supplied by Papop Co,Ltd., a local technology provider. The gas engine is manufactured by a Spanish manufacturer (Guascor). The bio-Scrubber and enclosed flare are manufactured by Thai companies Jiamphattana Energy International Co Ltd and Napatr Service (2004) Co. Ltd respectively. It is evident that the project activity is leading to a significant transfer of technology from developed countries to Thailand. Furthermore, all the suppliers will provide necessary training for the operation and maintenance of the equipments in the project activity which will further enhance the skill set of the local employees.

Environmentally safe and sound technology:

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[6] Measurement campaign – Annex 3.

[7] Papop – technology provider

The approval process by local authorities, which has been already successfully concluded by the project activity, include a general assessment of compliance by the project activity with the safety norms and regulations of the host country. Furthermore, all involved technology providers have a strong track record and experience with the relevant technologies, ensuring that all the equipments come with proper provisions for safety in line or even exceeding local regulations. The critical parameters for smooth operation of the system will be monitored as per the recommendations of the technology provider. The project activity has many provisions to guarantee safety and some of these include safety components such as pressure controller, gas analyser, automatic blowout, flame arrestor and safety switches. The operation manual for the project activity includes procedures on safety which will make sure that the operators are fully aware of preventive maintenance measures as well as emergency procedures.

The technology will not be substituted by a more efficient technology during the crediting period.

A.4.3 Estimated amount of emission reductions over the chosen crediting period:

The estimated amount of emission reductions from the small-scale project activity over first seven year crediting period is shown in the following table below.

Year	Annual estimation of emission reductions in tonnes of CO2e
2011	54,587
2012	54,587
2013	54,587
2014	54,587
2015	54,587
2016	54,587
2017	54,587
Total emission reductions (tonnes of CO2e)	382,109
Total number of crediting years	7
Annual average over the crediting period of estimated reductions (tonnes of CO2e)	54,587

Table 1: Estimated amount of emissions reductions

A.4.4. Public funding of the small-scale project activity:

No public funding from Annex I countries has been sought for this project.

A.4.5. Confirmation that the small-scale project activity is not a debundled component of a large scale project activity:

In reference to the "Guidelines on assessment of debundling for SSC project activities", version 03, EB54 (Annex 13)"

"A proposed small-scale project activity shall be deemed to be a debundled component of a large project activity if there is a registered small-scale CDM project activity or an application to register another small-scale CDM project activity:

(a) With the same project participants;

(b) In the same project category and technology/measure; and

(c) Registered within the previous 2 years; and

(d) Whose project boundary is within 1 km of the project boundary of the proposed small- scale activity at the closest point. "

The project participants confirm that there is no registered small-scale CDM project activity or an application to register another small-scale CDM project activity with the same project participants and whose project boundary is within 1 km of the Project boundary of the proposed small-scale activity, at the closest point. Therefore the project activity is not a de-bundled component of a large-scale project activity.

SECTION B. Application of a baseline and monitoring methodology

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

The following methodologies are applicable to the project activity:

Methane avoidance component:

AMS III.H: "Methane Recovery in Wastewater Treatment" (Version 16)

Thermal displacement component:

AMS I.C: "Thermal energy production with or without electricity" (Version 19)

Electricity generation component:

AMS I.D: "Grid connected renewable electricity generation" (Version 17)

For more information on these methodologies, please refer to the link:
http://cdm.unfccc.int/methodologies/SSCmethodologies/approved.html

The latest version of the following tools[8] will also be used in this Project activity:

- "Tool to calculate baseline, project and/or leakage emissions from electricity consumption", version 01;
- "Tool to determine project emissions from flaring gases containing methane", version 01;
- "Tool to calculate the emission factor for an electricity system", version 02.2.0

[8] http://cdm.unfccc.int/methodologies/SSCmethodologies/approved

- “Tool to calculate project or leakage CO2 emissions from fossil fuel combustion”, version 02.

B.2 Justification of the choice of the project category:

The project meets all the relevant applicability conditions of the methodologies, as described in the table below.

<u>Applicability conditions for AMS III.H</u>

Applicability Criteria	Project Status
1-This methodology comprises measures that recover biogas from biogenic organic matter in wastewater by means of one, or a combination, of the following options: ***a)*** *Substitution of aerobic wastewater or sludge treatment systems with anaerobic systems with biogas recovery and combustion;* ***b)*** *Introduction of anaerobic sludge treatment system with biogas recovery and combustion to an existing wastewater treatment plant without sludge treatment;* ***c)*** *Introduction of biogas recovery and combustion to an existing sludge treatment system;* ***d)*** *Introduction of biogas recovery and combustion to an existing anaerobic wastewater treatment system such as anaerobic reactor, lagoon, septic tank or an onsite industrial plant;* ***e)*** *Introduction of anaerobic wastewater treatment with biogas recovery and combustion, with or without anaerobic sludge treatment, to an untreated wastewater stream;* ***f) Introduction of a sequential stage of wastewater treatment with biogas recovery and combustion, with or without sludge treatment, to an anaerobic wastewater treatment system without biogas recovery (e.g. introduction of treatment in an anaerobic reactor with biogas recovery as a sequential treatment step for the wastewater that is presently being treated in an anaerobic lagoon without methane recovery)***	The project activity satisfies the applicability condition (f). In absence of the project activity, the wastewater would have been treated in open anaerobic lagoons without biogas recovery. Despite the Greenfield nature of the project, it is important to note that open anaerobic lagoons have been erected and used prior to commissioning of the UASB reactor. In absence of the project such open anaerobic lagoons would be the only existing wastewater treatment system. After the commissioning of the UASB reactor, the open anaerobic lagoons are used for post-treatment of the wastewater leaving the UASB reactor. Therefore, the project activity involves the introduction of a sequential stage of wastewater treatment with biogas recovery and combustion, without sludge treatment, to an anaerobic wastewater treatment system without biogas recovery. More details about the baseline determination in the context of a Greenfield project are provided in section B4
2- In cases where baseline system is anaerobic lagoon the methodology is applicable if: *a) The lagoons are ponds with a depth greater than two meters, without aeration. The value for depth is obtained from engineering design documents, or through direct measurement, or by dividing the surface area by the total volume. If the lagoon filling level varies seasonally, the average of the highest and lowest levels may be taken;*	The baseline scenario within the context of a Greenfield project is discussed in detail in section B.4. The outcome of the baseline determination is that the wastewater from the starch factory would have been treated in open anaerobic lagoons with depth greater than two meters and without aeration. This is also in line with the design of the open anaerobic lagoons that were in operation as main treatment system

Applicability Criteria	Project Status
*b) Ambient temperature above 15**deg**C, at least during part of the year, on a monthly average basis;* *c) The minimum interval between two consecutive sludge removal events shall be 30 days*	during the initial phase of the project and as post-treatment system after commissioning of the UASB reactor. The average monthly temperature in the region of project location[9] is above 15 deg C. The project activity is a Greenfield project and therefore there was no sludge generation in the baseline scenario. Therefore, the lagoons which would have been installed in the absence of the project activity satisfy the condition for anaerobic lagoons as mentioned in the methodology.
3- The recovered biogas from the above measures may also be utilised for the following applications instead of combustion/flaring: (a) ***Thermal, mechanical or electrical energy generation directly; or*** (b) *Thermal or mechanical, electrical energy generation after bottling of upgraded biogas, in this case additional guidance provided in Annex 1 shall be followed; or* (c) *Thermal or mechanical, electrical energy generation after upgrading and distribution, this case additional guidance provided in Annex 1 shall be followed:* (i) *Upgrading and injection of biogas into a natural gas distribution grid with no significant transmission constraints;* (ii) *Upgrading and transportation of biogas via a dedicated piped network to a group of end users; or* (iii) *Upgrading and transportation of biogas (e.g by trucks) to distribution points for end users.* (d) *Hydrogen production.* (e) Use as fuel in transportation application after upgrading.	The project activity satisfies the condition (a). The recovered biogas from the project activity will be utilised for thermal and electrical energy generation. The thermal energy will be generated using biogas in the thermal oil boiler and electrical energy will be generated in the gas engine. The thermal energy will be utilised in the starch drying process in the starch factory and electricity will be exported to the grid.
4-If the recovered biogas is used for project activities covered under paragraph 3 (a), that component of the project activity can use a corresponding category under type I.	The recovered biogas will be used as per the paragraph 3(a) above. The methodologies AMS.I.C and AMS.I.D will be used for the thermal and electrical component respectively.
5.-For project activities covered under paragraph 3	The project activity satisfies paragraph 3 (a) as

[9] http://www.climate-charts.com/Locations/t/TH48375.php

Applicability Criteria	Project Status
(b), if bottles with upgraded biogas are sold outside the project boundary, the end-use of the biogas shall be ensured via a contract between the bottled biogas vendor and the end-user. No emission reductions may be claimed from the displacement of fuels from the end use of bottled biogas in such situations. If however the end use of the bottled biogas is included in the project boundary and is monitored during the crediting period CO2 emissions avoided by the displacement of fossil fuel can be claimed under the corresponding Type I methodology, e.g. AMS-I.C "Thermal energy production with or without electricity".	mentioned above. The biogas generated is not bottled but will be utilised as fuel in the gas engine for electricity generation and in thermal oil boiler for thermal energy generation. Therefore, this condition is not relevant to the project activity.
6-For project activities covered under paragraph 3 (c) (i), emission reductions from the displacement of the use of natural gas are eligible under this methodology, provided the geographical extent of the natural gas distribution grid is within the host country boundaries.	The project activity satisfies paragraph 3 (a) as mentioned above. The biogas generated is not bottled but will be utilised as fuel in the gas engine for electricity generation and in thermal oil boiler for thermal energy generation. Therefore, this condition is not relevant to the project activity.
7-For project activities covered under paragraph 3 (c) (ii), emission reductions for the displacement of the use of fuels can be claimed following the provision in the corresponding Type I methodology, e.g. AMS-I.C	The project activity satisfies paragraph 3 (a) as mentioned above. Therefore, this condition is not relevant to the project activity.
8-In particular, for the case of 3 (b) and (c) (iii), the physical leakage during storage and transportation of upgraded biogas, as well as the emissions from fossil fuel consumed by vehicles for transporting biogas shall be considered. Relevant procedures in paragraph 11 of Annex 1 of AMS III.H "Methane recovery in wastewater treatment" shall be followed in this regard.	The project activity satisfies paragraph 3 (a) as mentioned above. Therefore, this condition is not relevant to the project activity.
9-For project activities covered under paragraph 3 (b) and (c), this methodology is applicable if the upgraded methane content of the biogas is in accordance with relevant national regulations (where these exist) or, in the absence of national regulations, a minimum of 96% (by volume).	The project activity satisfies paragraph 3 (a) as mentioned above. Therefore, this condition is not relevant to the project activity.
10-If the recovered biogas is utilized for the production of hydrogen (project activities covered under paragraph 3 (d)), that component of the project activity shall use the corresponding methodology AMS III.O "Hydrogen production using methane extracted from biogas".	The project activity satisfies paragraph 3 (a) as mentioned above. Therefore, this condition is not relevant to the project activity.
11-If the recovered biogas is used for project activities covered under paragraph 3 (e), that component of the project activity shall use corresponding methodology AMS-III.AQ "Introduction of Bio-CNG in road	The project activity satisfies paragraph 3 (a) as mentioned above. Therefore, this condition is not relevant to the project activity.

Applicability Criteria	Project Status
transportation".	
12-New facilities (Greenfield projects) and project activities involving a change of equipment resulting in a capacity addition of the wastewater or sludge treatment system compared to the designed capacity of the baseline treatment system are only eligible to apply this methodology if they comply with the relevant requirements in the General guidelines to SSC CDM methodologies. In addition the requirements for demonstrating the remaining lifetime of the equipment replaced, as described in the general guidelines shall be followed.	Given the fact that the starch factory itself was constructed and started operation in parallel to the development of the project activity, the project activity is considered a Greenfield project. The "General guidelines to SSC CDM methodologies" is complied and the details are given in section B.4.
13-The location of the wastewater treatment plant as well as the source generating the wastewater shall be uniquely defined and described in the PDD.	The location of the wastewater treatment plant has been clearly given in section A.4.1. The starch factory located at the same location is the source of wastewater generation.
14- Measures are limited to those that result in aggregate emission reductions of ***less than or equal to 60 kt CO_2*** *equivalent annually from all type III components of the project activity.*	The emission reductions to be achieved by the project activity from methane avoidance component (type III) are estimated at 44,021 tCO_2 per year, which is lower than 60 $ktCO_2e$ per year.

<u>**Applicability conditions for AMS.I.D**</u>

Applicability Criteria	Project Status
1. This methodology comprises renewable energy generation units, such as photovoltaic, hydro, tidal/wave, wind, geothermal and renewable biomass (a) ***Supplying electricity to a national or a regional grid;*** *or* (b) *Supplying electricity to an identified consumer facility via national/regional grid through a contractual arrangement such as wheeling.*	The project activity will use a part of biogas (a renewable fuel) which is captured from the methane avoidance component of the project activity to generate electricity in the gas engine. The electricity generated will be exported to the national grid. Therefore, the project activity satisfies this applicability condition. As per Table 2 in the methodology, the methodology ASM-I.F is not applicable to the project activity as the project is not supplying electricity to the user or mini grid based on fuel oil and/ or diesel fuel but to the grid. It can be thus concluded that AMS.I.D is the appropriate methodology.
2. This methodology is applicable to project activities that (a) ***install a new power plant at a site where there was no renewable energy power plant operating prior to the implementation of the project activity (Greenfield plant);*** *(b) involve a capacity addition ; (c) involve a retrofit of (an) existing plant(s); or (d) involve a replacement of (an) existing plant(s).*	The project activity will install a power plant at a site where there was no renewable energy power plant operating prior to the implementation of the project.

3. Hydro power plants with reservoirs that satisfy at least one of the following conditions are eligible to apply this methodology: • *The project activity is implemented in an existing reservoir with no change in the volume of reservoir;* • *The project activity is implemented in an existing reservoir, where the volume of reservoir is increased and the power density of the project activity, as per definitions given in the Project Emissions section, is greater than 4 W/m2;* • *The project activity results in new reservoirs and the power density of the power plant, as per definitions given in the Project Emissions section, is greater than 4 W/m2.*	The project activity involves generation of electricity from biogas and is not a hydro power plant. Therefore, this condition is not relevant.
4. If the new unit has both renewable and non-renewable components (e.g., a wind/diesel unit), ***the eligibility limit of 15 MW for a small-scale CDM project activity applies only to the renewable component.*** *If the new unit co-fires fossil fuel, the capacity of the entire unit shall not exceed the limit of 15 MW.*	The project activity entails in the installation of a gas engine which operates only on biogas. Therefore, the project has only the renewable component and has a total generation capacity of 952 kW_e which is less than 15MW.
5. Combined heat and power (co-generation) systems are not eligible under this category.	The project activity is not considered a co-generation system since electricity and thermal energy are produced in two separate and totally independent systems.
6. In the case of project activities that involve the addition of renewable energy generation units at an existing renewable power generation facility, the added capacity of the units added by the project should be lower than 15 MW and should be physically distinct from the existing units.	The project activity does not involve addition of renewable energy generation at an existing renewable power generation facility. The project activity implements a new gas engine at a location where there was no power generation.
7. In the case of retrofit or replacement, to qualify as a small-scale project, the total output of the retrofitted or replacement unit shall not exceed the limit of 15 MW.	The project activity does not involve any retrofitting or replacement.

<u>Applicability conditions for AMS.I.C.</u>

Applicability Criteria		Project eligibility
1	***This methodology comprises renewable energy technologies that*** *supply users[10] with thermal energy that displaces fossil fuel use.* ***These units include*** *technologies such as solar thermal water*	The project activity will capture biogas (a renewable fuel) from the project's wastewater treatment system and utilise a part of it for thermal energy generation in a

[10] E.g., residential, industrial or commercial facilities.

Applicability Criteria		Project eligibility
	heaters and dryers, solar cookers, energy derived from renewable biomass and other ***technologies that provide thermal energy that displaces fossil fuel.***	thermal oil boiler to substitute fossil fuel that would have been used to supply heat for the drying process of the starch factory. Therefore, the project activity meets this applicability criterion.
2	*The total installed/rated thermal energy generation capacity of the project equipment is equal to or* ***less than 45 MW thermal***[11] ***.***	The thermal generation capacity of the thermal oil boiler is 4,070 kW_{th}[12] which is less than 45 MW thermal as per the applicability criteria.
3	*For co-fired*[13] *systems, the total installed thermal energy generation capacity of the project equipment, when using both fossil and renewable fuel* ***shall not exceed 45 MW thermal.***	Thermal oil boiler is a dual fuel fired boiler. The total installed thermal energy generation capacity is 4,070 kW which is less than 45MW thermal.
4	*In the case of project activities that involve the addition of renewable energy units at an existing renewable energy facility, the total capacity of the units added by the project should comply with capacity limits in paragraphs 4 to 6 (of the methodology) and should be physically distinct*[14] *from the existing units.*	The Project activity does not involve an addition of renewable energy units at an existing renewable energy facility; thus this criterion is not relevant.
5	*Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category.*	Given the Greenfield nature of the project activity, it does not involve any retrofit or modification of an existing facility.
6	*New Facilities (Greenfield projects) and project activities involving capacity additions compared to the baseline scenario are only eligible if they comply with the related and relevant requirements in the General Guidelines to SSC CDM methodologies.*	The project activity utilizes a part of biogas in the thermal oil boiler in the starch factory for supplying heat to the starch drying process. Given the fact that the starch factory was itself constructed in parallel to the implementation of the project activity, the usage of biogas in the boiler is looked in the context of Greenfield projects and the same is demonstrated in baseline determination in PDD section B.4 using General Guidelines to SSC CDM methodologies.

[11] Thermal energy generation capacity shall be manufacturer's rated thermal energy output, or if that rating is not available the capacity shall be determined by taking the difference between enthalpy of total output (for example steam or hot air in kcal/kg or kcal/m^3) leaving the project equipment and the total enthalpy of input (for example feed water or air in kcal/kg or kcal/m^3) entering the project equipment. For boilers, condensate return (if any) must be incorporated into enthalpy of the feed.

[12] Technical specification of the boiler from the manufacturer.

[13] Co-fired system uses both fossil and renewable fuels.

[14] Physically distinct units are those that are capable of producing thermal/electrical energy without the operation of existing units, and that do not directly affect the mechanical, thermal, or electrical characteristics of the existing facility. For example, the addition of a steam turbine to an existing combustion turbine to create a combined cycle unit would not be considered "physically distinct".

Applicability Criteria		Project eligibility
7	*If electricity and/or steam/heat produced by the project activity is delivered to a third party i.e. another facility or facilities within the project boundary, a contract between the supplier and consumer(s) of the energy will have to be entered into that ensures there is no double-counting of emission reductions.*	The project activity will not deliver directly the heat to the starch factory. However, a part of biogas which will be generated from the methane avoidance component of the project will be delivered which will be combusted in the boiler in the starch factory. The contract between supplier (Maesod Biogas Company Ltd) and consumer (Maesot Starch Company Ltd) is available which clearly states that only the supplier can claim emission reductions.
8	*If the project activity recovers and utilizes biogas for power/heat production and applies this methodology on a stand alone basis i.e. without using a Type III component of a SSC methodology, any incremental emissions occurring due to the implementation of the project activity (e.g. physical leakage of the anaerobic digester, emissions due to inefficiency of the flaring), shall be taken into account either as project or leakage emissions.*	The project activity recovers and utilises biogas for both power and heat generation. However, AMS-I.C is not used on a standalone basis but used with AMS-III.H. All the project or leakage emissions are taken into account.

From the above, the project activity meets all the relevant criteria of the applicable methodologies.

B.3. Description of the project boundary:

As per the AMS III.H, AMS I.C and AMS I.D., the Project boundary shall respectively include the following:

Project boundary for AMS III.H is given as per the paragraph 15 of the methodology:

> *"The project boundary is the physical, geographical site where the wastewater and sludge treatment takes place in baseline and project situation. It covers all facilities affected by the project activity including sites where the processing, transportation and application or disposal of waste products as well as biogas takes place."*

As per paragraph 16 of the methodology, implementation of the project activity at a wastewater and/or sludge treatment[15] system will affect certain sections of the treatment systems while others may remain unaffected. As the project activity is implemented in a Greenfield location, the waste water treatment system that would have been affected will be the open anaerobic lagoon system. The waste water from the starch factory would no longer have been treated in the open anaerobic lagoons. The waste water will be first treated in the biogas reactor before being fed to the open lagoons. The COD levels entering the open lagoons in the project activity will be much lower than those in the baseline scenario. The resulting methane emissions will be considered under the project emissions. Furthermore, the electricity consumption in the baseline and project wastewater treatment system will also be affected. These emission sources are also dealt

[15] There was no sludge generation or treatment in the baseline

separately in the baseline and project emission calculations. In the project activity, the pre-treatment process unit, the biogas system and the subsequence open lagoon system (post treatment) including the utilisation of effluent are covered within the boundary. The exclusion of sections or the components of the treatment system affected by project activity are taken into account for ex ante GHG calculation and further justified in the section B 6.3.

Project boundary for AMS I. C as per paragraph 15 of the methodology is given as:

	Boundary scope	*Included?*
a)	*All plants generating power and/or heat located at the project site, whether fired with biomass, fossil fuels or a combination of both;*	*Yes, the thermal oil boiler which will be using biogas to generate heat is included in the project boundary.*
b)	*All power plants connected physically to the electricity system (grid) that the project plant is connected to;*	*Not relevant, but grid is included in the project boundary in the context of AMS-I.D for the electricity component of the project activity.*
c)	*Industrial, commercial or residential facility, or facilities, consuming energy generated by the system and the processes or equipment affected by the project activity;*	*Yes, the starch drying process consuming heat supplied by the thermal boiler is included in the project boundary.*
d)	*The processing plant of biomass residues, for project activities using solid biomass fuel (e.g. briquette), unless all associated emissions are accounted for as leakage emissions;*	*Not relevant as the project activity does not involve processing of biomass residues.*
e)	*The transportation itineraries, if the biomass is transported over distances greater than 200 kilometres, unless all associated emissions are accounted for as leakage emissions;*	*Not relevant as project activity utilises biogas which is generated next to the starch factory and transported using pipelines.*
f)	*The site of the anaerobic digester in the case of project activity that recovers and utilizes biogas for power/heat production and applies this methodology on a stand alone basis i.e. without using a Type III component of a SSC methodology.*	*Yes, the site of anaerobic digestor is already included in the context of AMS-III.H*

Project boundary for AMS I.D as per paragraph 9 in the methodology is given as:

"The spatial extent of the project boundary includes the project power plant and all power plants connected physically to the electricity system that the CDM project power plant is connected to."

The GHG gases considered in the analysis are given in the following table:

	Source	**Gas**		**Justification / Explanation**
Baseline	Wastewater treatment processes	CH_4	Included	The major source of emissions in the baseline from open lagoons (decay of organic matter in anaerobic conditions).
		N_2O	Excluded	Excluded for simplification. This is conservative.
		CO_2	Excluded	CO2 emissions from the decomposition of organic waste are not accounted for

	Electricity consumption/ Electricity generation	CO_2	Excluded (AMS.III.H) Included (AMS.I.D)	AMS.III.H component: Baseline emissions from electricity consumption for the baseline wastewater treatment system are excluded as this will be a very small quantity. Further, it is conservative to not include the baseline emissions from this source. AMS.I.D component: The project activity involves the installation of a new grid-connected renewable power unit, whereas the baseline scenario is the electricity delivered to the grid that, in the absence of the project, would have been generated by the operation of grid-connected power plants and by the addition of new generation sources.
		CH_4	Excluded	Excluded for simplification. This is conservative.
		N_2O	Excluded	Excluded for simplification. This is conservative.
	Thermal energy generation	CO_2	Included	The thermal energy would have been generated by using bunker oil in the thermal oil boiler in the baseline scenario.
		CH_4	Excluded	Excluded for simplification. This is conservative.
		N_2O	Excluded	Excluded for simplification. This is conservative.
Project activity	Wastewater treatment processes	CH_4	Included	The treatment of wastewater under the project activity may cause different emissions: (i) Methane emissions from lagoons (ii) Fugitive emissions due to inefficiencies in capture systems (iii) Methane emissions from flaring
		CO_2	Excluded	CO_2 emissions from the decomposition of organic waste are not accounted for
		N_2O	Excluded	No land application of sludge
	On-site electricity use	CO_2	Included	If the biogas reactor uses electricity generated from the biogas fired gas engine, this will be excluded. However, if the electricity is sourced from the grid, this will be included.
		CH_4	Excluded	Excluded for simplification.
		N_2O	Excluded	Excluded for simplification
	On-site fossil fuel consumption	CO_2	Included	Fossil fuel used in the dual-fuel boiler for thermal energy generation shall be monitored and considered in emission reduction calculations.
		CH4	Excluded	No on-site fossil fuel consumption in the project activity
		N20	Excluded	No on-site fossil fuel consumption in the project activity

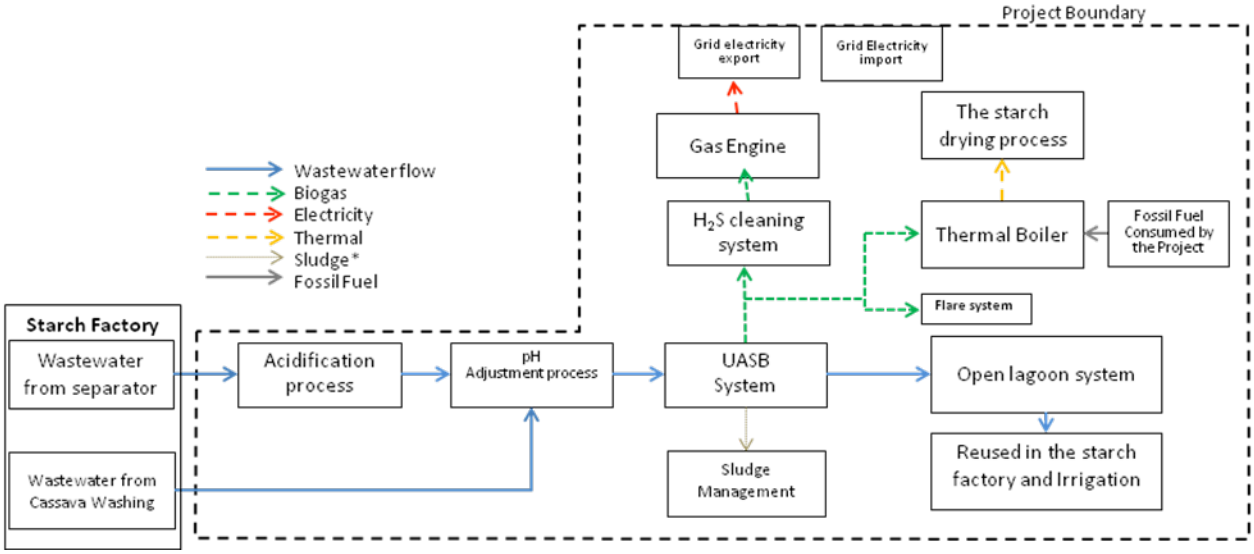

Figure: Project boundary diagram

B.4. Description of baseline and its development:

Baseline for methane avoidance component

As per paragraph 12 of the methodology AMS-III.H., Greenfield project activities shall comply with the relevant requirements in the "General guidelines to SSC CDM methodologies" version 17[16]. Since, the project activity is implemented in a Greenfield location; the project activity should follow guidance given in the paragraph 19. The demonstration should include the assessment of the alternatives of the project activity using the following steps:

Step 1:

Identify the various alternatives available to the project proponent that deliver comparable level of service including the proposed project activity undertaken without being registered as a CDM project activity.

The main output or service of this component of the project activity is the treatment of effluent waste water which in turns leads to generation and capture of biogas. The by-products of the project activity arising from the utilisation of biogas captured are the production of heat and electricity.

Therefore, the alternative scenarios that are available to the project participants and that provide outputs or services with comparable quality, properties and application as the proposed small-scale CDM project activity are:

Alternative 1: Methane recovery using anaerobic digester and utilisation for heat and electricity generation (proposed project without CDM assistance)
Alternative 2: Open anaerobic lagoon based wastewater treatment system (business as usual scenario)

[16] EB61, Annex 21.

Alternative 3: Aerobic wastewater treatment system
Alternative 4: Direct discharge to water bodies
Alternative 5: Methane recovery using anaerobic digester and flaring

Step 2:

List the alternatives identified per Step 1 in compliance with the local regulations (if any of the identified baseline is not in compliance with the local regulations, then exclude the same from further consideration).

Alternatives 1, 2, 3 and 5 are in compliance with current laws and regulations in Thailand, which allow the use of open lagoon systems and other wastewater treatment technologies for wastewater treatment. The effluent standard in Thailand is regulated by the "Notification of the Ministry of Science, Technology and Environment, No. 3, B.E.2539 (1996)"[17] published in the Royal Government Gazette, Vol. 113 Part 13 D, dated February 13, B.E.2539 (1996). According to this regulation the COD of released wastewater is not allowed to exceed 120 mg/litre and the 5-day BOD (BOD_5) shall not exceed 20 mg/litre. However there is an exception for starch plants which stipulates that BOD_5 should not exceed 60 mg/litre[18]. These regulations only apply if the starch factory releases wastewater outside its premises which is not the case.

There is no other regulatory requirement for the implementation of a specific wastewater treatment technology, such as an anaerobic digester or aerobic treatment system, at tapioca starch processing plants.

Alternative 4 is not in compliance with the effluent discharge standards set by the laws and regulations of Thailand. Therefore, alternative 4 cannot be considered as the baseline and is excluded from further assessment.

Step 3:

Eliminate and rank the alternatives identified in Step 2 taking into account barrier tests specified in attachment A to Appendix B of the simplified modalities and procedures of SSC CDM.

Technical barrier

Alternative 1 is seen as a high risk alternative with limited performance guarantee on biogas generation and quality. The performance of this alternative depends on the quantity and quality of biogas generated, starting up and maintaining the anaerobic digestor at optimal conditions. Anaerobic digestion systems are unstable systems and require several control loops to keep the digester parameters within appropriate levels. There are different parameters, such as the COD load of the wastewater, the pH-value, TSS (total suspended solids) and the temperature which have an impact on the performance of the digester[19]. An anaerobic digestion system is a biological system which has to be balanced constantly to provide best conditions for the anaerobic bacteria. Therefore the proper operating of the control system is essential for the output of biogas.

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[17] Ministry of Science, Technology and Environment. Thailand (1996). Notification the Ministry of Science, Technology and Environment, No. 3, B.E.2539 (1996). Cited at: http://infofile.pcd.go.th/law/3_4_water.pdf (Document in Thai)
[18] Pollution Control Department. Thailand (2004). Industrial effluents standards. Cited at http://www.pcd.go.th/info_serv/en_reg_std_water04.html (Document in English)

[19] Effect of temperature on the anaerobic digestion of palm oil mill effluent, Electronic Journal of Biotechnology. - http://ejb.ucv.cl/index.php/ejbiotechnology/article/viewFile/v10n3-7/124

Improper operation of the digester or the wrong use of chemical substances harm the bacteria and lead very often to the collapse of the reactor system[20]. Poor performance of the digester affects adversely the quantity and the methane content of the biogas. However, for electricity generation the methane content of the biogas is crucial. In Thailand, there are limited technical capabilities for operation of such anaerobic reactor technology in the starch sector. The lack of technical knowledge is often related to the fact that technologies have been developed abroad without proper technology or know-how transfer[21],[22]. There is also a lack of skilled and trained operators for biogas plants in Thailand, which is often related to the remote location of biogas plants and the lack of qualified professionals in rural areas. This is another reason why operators of starch factories hesitate to use this technology. Staff has to be trained to ensure an uninterrupted handling of the wastewater treatment system and continuous generation of biogas for heat and electricity generation.

The project proponent has no prior experience in operating and maintaining an anaerobic digestion process with a methane recovery system. Since biogas plants require sophisticated operation procedures to manage the complicated biological, gas and electrical components of the project, specific and detailed training of employees is required, which is a significant challenge for the company. It is clear that this alternative faces general technical barriers. In addition to potential technical barriers, the project activity faces other barriers, which are discussed in more detail in Section B.5. Therefore, Alternative 1 is not excluded at this stage.

Alternative 2 has been a common practice of handling wastewater from tapioca starch production in Thailand for the last thirty years[23]. The related requirements in terms of technology, skills and labour required for such lagoon systems are far below the requirements of anaerobic reactor systems and are readily available in Thailand. The risk level associated with such lagoon systems are considered as very low because of their extremely simple and robust operation principles, as well as their history and the expertise available in the agricultural sector in Thailand. For the implementation of a lagoon system large areas of land are necessary on which several ponds are dredged. Through gravity, the effluent flows directly from one lagoon to the next. Due to a long residence time of wastewater in the lagoons, the biological process is less efficient but more robust, delivering ultimately the required effluent quality levels as per Thai environmental regulations. Open anaerobic lagoons require extremely limited operation and maintenance due to the self-regulatory nature of the systems. Hence, lagoons are a very cost-effective solution, do not require advanced technology and are easy to operate and maintain[24]. Therefore, almost all starch plants in Thailand use or have used (prior to implementation of biogas reactors as CDM projects) open lagoon systems for the treatment of wastewater. This scenario is therefore

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[20] The microbiology of anaerobic digester (2003). M. H. Gerardi. Wastewater microbiology series. – Page 102 - http://uctm-biotechnology.org/The_Microbiology_of_Anaerobic_Digesters.pdf

[21] Biogas from wastewater in palm oil mill project'. ASEAN renewable energy project competition 2007. Cited at: http://www.aseanenergy.org/download/aea/renewable_energy/2007/awardees/on%20grid_biogas%20from%20waste water%20in%20palm%20oil%20mill_th.pdf

[22] IP-Institut für Projektplanung GmbH on behalf of GTZ (1997). Environmental Management Guideline for the Palm Oil Industry, Thailand. – Chapter 6 review of suitable wastewater treatment technologies. Cited at:

http://www.elaw.org/assets/pdf/th.palm.oil.industry.guidelines.pdf

[23] Rajbhandari, B.K., Annachhatre, A.P. 2004, Anaerobic ponds treatment of starch wastewater: case study in

Thailand. Bioresource Technology 95 (2004) 135–143. - http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V24-4BX7B3M-3&_user=10&_coverDate=11%2F30%2F2004&_rdoc=1&_fmt=high&_orig=gateway&_origin=gateway&_sort=d&_docanchor=&view=c&_searchStrId=1670841409&_rerunOrigin=google&_acct=C000050221&_version=1&_urlVersion=0&_userid=10&md5=71d828bbd614951f13b186fab9fa8aeb&searchtype=a

[24] Cinara, 2004 "Waste stabilization ponds for wastewater treatment, International Water and Sanitation Centre"

http://www.irc.nl/page/8237

in line with the business as usual scenario, which is further elaborated under Step 4 below. It can be concluded that Alternative 2 does not face technical barriers.

Alternative 3 is well established and commonly used for both domestic and industrial wastewater treatment in many parts of the world. However, aerobic treatment is commonly used for wastewater with low COD content. There is no reference to or experience with this type of technology in the tapioca starch industry in Thailand and no starch factory operator is considering the use of this technology at this point in time. Furthermore aerobic treatment requires also skilled operators and sophisticated systems for control and is considered costly due to the high energy demand and the large volume of sludge that will be produced. Oxygen is supplied to the system through air compression which consume a lot of electricity, The necessary requirements, both in terms costs and skills to operate and maintain such systems is much higher than the use of an anaerobic lagoon. Furthermore, a significant amount of sludge generated by aerobic systems must be disposed of, which adds to operational complexity and costs. Considering lack of interest in this technology, technical barriers are deemed less important than investment barriers, which are discussed in more detail below.

Alternative 4 is already excluded.

Alternative 5 is not considered by project operators due to commercial reasons as it creates no benefits in form of biogas utilisation and is not required by law. Technical reasons are deemed irrelevant.

Access-to-finance barriers

Alternative 1 entails high investment and O&M costs and uncertain commercial returns (from the production and use of biogas).

According to the *Energy Conservation and Renewable Energy Division* and *Energy Policy and Planning Division* of the Ministry of Environment, Government of Thailand *"Most of the tapioca starch plants choose to retain wastewater in their open lagoons because of insufficient knowledge /confidence in the technology, high investment cost compared to cheap land price, the resulting operating cost throughout the treatment life*"[25]. Therefore penetration of other advanced wastewater treatment technologies is very low in Thailand and biogas projects are considered highly risky by the financiers. Hence, financing of biogas project in starch industry is regarded as a constraint[26]. Due to high risks associated with such kind of projects even, without subsidies, it is very difficult to obtain a loan approval[27]. This was also evident from the difficulties faced by the project proponent in securing loan for the project activity (see Section B.5 for more details).

In recent years (2003- 2005), Ministry of Environment started a pilot demonstration of biogas system in starch industry in four different wastewater treatment technology. Nine factories were selected and received financial support from the Energy Conservation Promotion Fund (ENCON)[28]. Furthermore, it

[25] The Promotion of Biogas from Wastewater as An Alternative Energy and for Environmental Improvement, published by the Energy Conservation and Renewable Energy Division and Energy Policy and Planning Office (EPPO), 2007 Page no. 47. - http://www.eppo.go.th/encon/report/BioGasMartBook/index.html

[26] Renewable Energy in Asia: The Thailand Report. An overview of the energy systems, renewable energy options, initiatives, actors and opportunities in Thailand, 2005. Australian Business Council for Sustainable Energy, Page No. 5. - http://www.lowcarbonoptions.net/resources/Policy-&-Measures/Policies-and-Measures--Thailand/Renewable_energy_Thailand.pdf

[27] Prasertsan, S. B. Sajjakulnukit (2006). Biomass and biogas energy in Thailand: Potential, opportunity and barriers. Renewable Energy 31:599–610.

has been demonstrated that access to finance is the main barrier which makes the projects unviable. As analyzed in detail in Section B.5, the project activity faces prohibitive access-to-finance barriers and could not have been implemented without CDM. Given the outcome of Section B.5, Alternative 1 (the project activity without CDM) can be excluded.

Alternative 2 creates acceptable operational costs to achieve compliance with domestic effluent regulation. The anaerobic open lagoon technology is well established technology. Open anaerobic lagoons require very low investment and have lower operation and maintenance costs[29], as compared to alternative systems such as anaerobic reactors and aerobic systems. Given the significantly lower investment cost, it is clear that Alternative 2 does not face significant financial barriers and represents a plausible baseline scenario.

Alternative 3 entails high investment and very high O&M costs[30] in comparison to alternatives 1 and 2. The major reason for high O&M costs for treating wastewater with high organic content in aerobic systems is the very high electricity demand for forced aeration and high costs associated to sludge disposal as compared to anaerobic treatment systems. Due to high investment and O&M costs and the lack of commercial returns from energy production, it is clear that Alternative 3 would face similar or even stronger access-to-finance barriers as the project activity (see Section B.5 for more details). Therefore, the alternative can be excluded from further analysis.

Alternative 4 is already excluded.

Alternative 5, anaerobic digester with methane recovery and flaring, also entails high investment and O&M costs and no returns as the produced biogas is destroyed without use. There will be no expected revenue generation from the project activity and therefore, this alternative is not considered a practical option because it would face even greater access-to-finance barriers as the project activity. Therefore, the alternative is excluded from further analysis.

Alternatives scenarios 3 and 5 are prevented by at least one barrier as shown above. Therefore, these scenarios are eliminated from further consideration. No barriers have been identified for Alternative 2 (Open anaerobic lagoon based wastewater treatment system). Alternative 1 (proposed project without CDM assistance) is discussed in detail in Section B.5., where it is concluded that the project activity would not be implemented without support from CDM. Therefore, Alternative 1 is ruled out as potential baseline scenario.

Step 4:

Only one alternative remains (Alternative 2), which is not the proposed project activity undertaken without being registered as a CDM project activity and is considered as the most plausible baseline scenario. The Alternative 2 - open anaerobic lagoon based wastewater treatment system also corresponds to the baseline scenario (f) of AMS.III.H; the project activity is eligible under the methodology.

Conclusion:

[28] Energy Policy and Planning Office, Ministry of Energy, Seminar on the Promotion of Production of Biogas from Wastewater as an Alternative Energy and for Environmental Improvement, At Ballroom, Sirikit Convention Centre 29 August 2007, pp.46-

47 - http://www.eppo.go.th/encon/report/BioGasMartBook/index.html

[29] Cinara, 2004 "Waste stabilization ponds for wastewater treatment, International Water and Sanitation Centre" - http://www.irc.nl/page/8237

[30] http://www.intechopen.com/source/pdfs/14547/InTech-Anaerobic_treatment_of_industrial_effluents_an_overview_of_applications.pdf

From the above discussion, it has been demonstrated that the wastewater would have been treated in open anaerobic lagoon in the absence of the project activity. The project activity therefore fulfills the applicability condition of the applicable methodology AMS.III.H.

(f) Introduction of a sequential stage of wastewater treatment with biogas recovery and combustion, with or without sludge treatment, to an anaerobic wastewater treatment system without biogas recovery (e.g. introduction of treatment in an anaerobic reactor with biogas recovery as a sequential treatment step for the wastewater that is presently being treated in an anaerobic lagoon without methane recovery).

Explanation and justification of key assumptions for baseline scenario:

As per paragraph 28 of the methodology AMS III.H, '*In the case of Greenfield projects, one of the following procedures shall be used to determine the baseline emissions:*

Paragraph 2– For Greenfield and capacity expansion projects, one of the following procedures shall be used:

a) Values obtained from a measurement campaign in a comparable existing wastewater treatment plant i.e. having similar environmental and technological circumstances for e.g. treating similar type of wastewater. Average values from the measurement campaign shall be used and the result shall be multiplied by 0.89 to account for the uncertainty range (30% to 50%) associated with this approach.

b) Value provided by the manufacturer/designer of a Greenfield wastewater treatment plant using the same technology, demonstrated to be conservative, e.g. average values from the top 20 percent plants with lowest emission rate per ton COD removed among the plants installed in the last five years designed for the same country/region to treat the same type of wastewaters as the project activity.

Option (a) has been selected and a 10 day COD campaign data has been used from a comparable starch factory treating wastewater in open anaerobic lagoons in the baseline. The data has been taken from Chaophyapeuchrai 2999 (Kamphaengphet) Co., Ltd. which is located at a distance of 157km[31] from the project activity. This is further clarified in the table below against the conditions from the methodology AMS.III.H.

Condition	Justification
1- The two sources of wastewater (wastewater treated in the selected plant and from the project activity) are of the same type, e.g. either domestic or industrial wastewater	Yes, the wastewater are of the same type i.e industrial wastewater coming from starch production process.
2- The selected plant and the baseline plants employ the same treatment technology (e.g.	Yes, the selected plant and the baseline plant (baseline scenario for the project activity) employed the

[31] Google earth.

anaerobic lagoons or activated sludge), and the hydraulic retention times in their biological and physical treatment systems do not vary by more than 20%; and	technology of open anaerobic lagoons. The selected plant is also developed as a CDM project activity[32]. The project activity is a Greenfield project activity but the hydraulic retention time would have been same with that of the selected plant as the wastewater is stored in the open lagoons for indefinite time as a common practice.
3- For project activity treating industrial wastewater, both industries have the same raw material and final products, and apply the same industrial technology.	Yes, both the plants use the same raw material i.e. cassava and have the same final products i.e. native starch. Both the plants also use same industrial technology.

Therefore, all the conditions form the methodology are met. The COD campaign data is summarized in the Annex 3 of the PDD.

Thermal displacement component:
The project activity generates biogas as a part of waste water treatment system equipped with biogas recovery. A part of this biogas will be sent to the thermal oil boiler to generate heat for the starch drying process. In the absence of project activity, the starch drying process would have obtained heat from a thermal oil boiler using heavy fuel oil. The starch factory was already using a thermal oil boiler to generate heat using heavy fuel oil before the implementation of the project activity. The biogas generated in the project activity displaces fossil fuel used in the thermal oil boiler. However, the thermal oil boiler has a history of operation which is less than one year; detailed records on fuel consumption and output are not available as per the requirements of the methodology. Furthermore, construction of the starch factory and the associated starch drying process started in parallel to the implementation of the project activity; therefore, the most plausible energy supply source is established in accordance with the guidance on Greenfield projects in the general guidelines to SSC CDM methodologies[33].

As per paragraph 19 of the above mentioned guidelines, the most plausible baseline scenario is established using the following steps:

Step 1: *Identify the various alternatives available to the project proponent that deliver comparable level of service including the proposed project activity undertaken without being registered as a CDM project activity.*

The alternatives available to the project proponent are:
Alternative 1: To utilise fuel oil to generate heat in the thermal boiler
Alternative 2: To use coal to generate heat in the thermal boiler
Alternative 3: To use biomass to generate heat in the thermal boiler
Alternative 4: To use biogas, the proposed project activity without being registered as a CDM project activity.

Step 2:
All the above mentioned alternatives are in compliance with the local regulations.

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[32] http://cdm.unfccc.int/Projects/Validation/DB/NNWT4CRIXKFL0AFBRFXYBFR594EK1B/view.html

[33] EB61 Annex 21

Step 3:
The alternatives as identified in step 1 and step 2 above are eliminated taking into account barrier test specified in attachment A to Appendix B of the simplified modalities and procedures of SSC CDM. As per the attachment A to Appendix B, the project proponent can eliminate alternatives by using any one of the following barriers:

a) Investment barrier
b) Technological barrier
c) Barrier due to prevailing practice
d) Other barriers

Option (c) – Barrier due to prevailing practice has been selected to eliminate alternatives.
It is a prevailing practice in Thailand to use fuel oil almost exclusively for heat generation especially Food industry which includes Tapioca starch industry as well. If we look at the share of energy consumption in Thailand as a whole, this was dominated by oil having a share of 42%, natural gas being 38% and coal at only 11% in 2007[34]. If we look at the share of coal consumption in the manufacturing sector, food processing industry consumes less than 1%[35] of the total coal consumption in the manufacturing sector. Tapioca industry being part of the food processing sector, consumes only a negligible amount of coal for its energy requirements. If we look at information from the Department of Alternative Energy Development and Efficiency (DEDE)[36], Ministry of Energy Thailand, majority of coal consumption is in the power sector (81%) and the rest is used by the industrial sector (19%) ranked by consumption as cement, paper, fibre, food, lime tobacco, metal, battery and others. It is clear that food sector (including tapioca starch production) consumes negligible amount of coal to meets its energy requirements. The fact that fuel oil is almost exclusively used in the Tapioca industry is further highlighted by an assessment by Thai Tapioca Starch Association (TTSA)[37] which mentions that fuel oil is used to generate heat for the drying process in the starch manufacturing.

From the above discussion, the prevailing practice is to use fuel oil in starch industry. Options like coal and biomass are not a preferred option to generate heat in the starch manufacturing process in Thailand. Alternative 4 which is about the use of biogas is already eliminated as per the discussion under the methane avoidance component in this section and in section B.5. The biogas will be available only if the wastewater treatment as per the project activity is implemented. In the absence of the project activity, there would not be any biogas available as a fuel option in the thermal boiler. Therefore, alternative 1 is the only alternative which is not prevented due to the prevailing practice barrier and therefore is not eliminated. This is also strengthened by the fact that the starch factory was already using fuel oil in the thermal boiler before the implementation of the project activity and generation of biogas.

Step 4:
Only one alternative is remaining after the Step 3, which is not the proposed project activity and it also corresponds to one of the baseline scenarios provided in the methodology.

Therefore, "Alternative 1 – To utilise fuel oil to generate heat in the thermal boiler" is the baseline scenario for the project activity's heat component.

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[34] Page 5- http://www.egcfe.ewg.apec.org/publications/proceedings/CFE/Xian_2007/1-3_Suksumek.pdf

[35] Page 7 - http://www.egcfe.ewg.apec.org/publications/proceedings/CFE/Xian_2007/1-3_Suksumek.pdf

[36] http://www3.dede.go.th/dede/index.php?id=701

[37] http://www.thaitapiocastarch.org/article01.asp

Electricity generation component:
In accordance to Paragraph 10 of the methodology AMS I.D. (Version 17):

> *"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 into the grid."*

The project activity involves the installation of a new grid-connected renewable power plant and therefore, the baseline scenario is the electricity delivered to the grid by the project activity. In the absence of the project activity, the electricity would have been generated by the operation of grid-connected power plants and by the addition of new generation sources.

Furthermore, the baseline emissions shall be calculated using Paragraph 11 in the methodology:

> *"The baseline emissions are the product of electrical energy baseline $EG_{BL,y}$ expressed in MWh of electricity produced by the renewable generating unit multiplied by the grid emission factor."*

The formula for the calculation is given in section B.6.1. The emission factor has been calculated following the approach given in paragraph 12 (a) of the methodology.

> "12 *(a) A combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) according to the procedures prescribed in the 'Tool to calculate the emission factor for an electricity system"*

Please refer to Annex 3 for more information on the choice for emission factor.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered small-scale CDM project activity:

The project activity, as explained in earlier sections, reduces Greenhouse Gas (GHG) emissions by capturing the methane that would have escaped into the environment from anaerobic reduction of organic matter in open lagoons and also by using the captured methane to replace the use of fossil fuel in heat boiler and to generate power replacing grid electricity. The benefits from CDM are integral part in the viability of the project. The following outlines a few key milestones in the project's life cycle and discussion on additionality with respect to access to finance barrier.

Time schedule of the project activity and prior consideration of CDM
The following table gives an overview of the timeline of the key milestones in the project implementation so far.

Date	**Event**	**Reference Document**
June 2008	Proposal from Papop[38] including CDM benefits	Copy of proposal
25/06/2008	Contract signed with Papop which included services for CDM	Copy of contract
14/01/2009	Maesod Biogas Co., Ltd. submitted letter of intent (LoI) to Thai DNA – **CDM notification**	LoI sent to TGO (Thai DNA)

[38] Biogas technology provider

Date	Event	Reference Document
11/02/2009	Amendment to the contract with Papop	Copy of contract
25/02/2009	First payment to technology supplier – **Start date of project activity**	Payment receipts
15/05/2009	MBG submitted the letter of intent (LoI) to UNFCCC – **CDM notification**	LoI sent to UNFCCC
08/06/ 2009	ERPA signed between MBG and Swiss Carbon Assets Ltd.	ERPA between MBG and Swiss Carbon Assets Ltd.
24/08/2009	The local stakeholders were invited to participate in the local stakeholder consultation meeting.	Minute of local stakeholder consultation report
05/11/ 2009	Issuance of the biogas operation license	MBG Operating license
16/12/2009	Contract signed with DOE (RINA)	Copy of DOE contract
Jan'10-Feb'10	PDD webhosted	UNFCCC
6-8th May 2010	Validation site visit	Audit plan from RINA
11/05/2010	The starch factory started operation.	The starch factory operation license
06/07/2010	Issuance of Letter of approval by host country (Thai DNA)	Letter of approval by TGO
16/09/2010	Letter of approval issued from Sweden	Copy of LoA
02/11/2010	MBG signed new ERPA with Swedish Energy Agency.	ERPA between MBG and Swedish Energy Agency.
08/11/2010	MBG terminated ERPA with Swiss Carbon Assets Ltd.	The termination agreement between MBG and Swiss Carbon Assets Ltd.

As per the above timeline, CDM has been crucial throughout the progress of the project activity. In reference to the *"Guideline on the demonstration and assessment of prior consideration of the CDM"*, EB62 – Annex 13[39], for project activities with a starting date on or after 02 August 2008, the project participant must inform a Host Party DNA and the UNFCCC secretariat in writing of the commencement of the project activity and of their intention to seek CDM status. In line with the same, the project proponent informed the DNA and the UNFCCC about their intention to seek CDM status as per the above timeline. Therefore, the project activity fulfills the requirement of prior consideration of the CDM.

Additionality demonstration

As per attachment A of Appendix B of the *Simplified Modalities and Procedures for Small-Scale CDM Project Activities*, additionality of the project shall be demonstrated by providing an explanation to show that the project activity would not have occurred anyway due to at least one of the following barriers: (a) investment barrier, (b) technological barrier, (c) barrier due to prevailing practice, and (d) other barriers.

Furthermore, in reference to the "**Non-binding best practice examples to demonstrate additionality for SSC project activities**", Annex 34, EB35[40], project participants shall provide an explanation to show that the project activity would not have occurred due to at least one of the following barriers:

(a)- **Investment barrier:** a financially more viable alternative to the project activity would have led to higher emissions

(b)- **Access to finance barrier:** the project activity could not access appropriate capital without consideration of the CDM revenues

[39] http://cdm.unfccc.int/Reference/Guidclarif/reg/reg_guid04.pdf

[40] http://cdm.unfccc.int/Reference/Guidclarif/ssc/methSSC_guid15_v01.pdf

(c)- **Technology barrier:** a less technologically advanced alternative to the project activity involves lower risks due to the performance uncertainty or low market share of the new technology adopted for the project activity and so would have led to higher emissions
(d)- **Barrier due to prevailing practices:** prevailing practice or existing regulatory or policy requirements would have led to implementation of a technology with higher emissions;
(e)-**Other barriers** such as institutional barriers or limited information, managerial resources, organizational capacity, or capacity to absorb new technologies.

In line with the above guidance, the additionality is demonstrated using option (b) Access to finance barrier.

Access to Finance barrier

Industry-specific background information with regards to availability of finance

The tapioca processing industry is considered to be one of the largest food processing industrial sector in Thailand. However, the growth of the tapioca starch industry has resulted in heavy water pollution as it generates large amount of solid waste and wastewater with high organic content.

Government of Thailand is promoting renewable energy based on the investment subsidy mechanism in various sectors. Following the initial biogas promotion in the livestock sector, the Ministry of Energy expanded its biogas campaign into the agro-industrial sector, and focused on the tapioca starch sub-sector. During 2003–2005, pilot demonstrations of biogas system in the starch industry were carried out by receiving financial support from the Energy Conservation Promotion Fund (ENCON). As per the report there has been insufficient knowledge / confidence in the available technology. Besides, wastewater treatment technology comes together with high investment cost and high operating cost. As a result, most of manufacturers choose to retain wastewater in open ponds within their factory. The treatment of wastewater in the open lagoons is the least cost option with minimum operating costs.

Therefore penetration of advanced wastewater treatment technologies (for e.g. UASB) is difficult in Thailand and biogas projects are considered high risk propositions by financiers.

It is important to note that private investment in the renewable/clean technology sector in Thailand faces some key challenges. The following is the outcome of the Investment plan[41] for The Clean Technology Fund (CTF)[42].

The key challenge in stimulating private investment in cleaner technology is overcoming institutional, technical, market, and financial barriers considered as high by investors. Although there is ample liquidity in the domestic financial market, lending to renewable energy projects remain limited. ***Access to affordable financing is a key barrier to investors***, suggesting there are structural rigidities in the renewable power generation development market. Key factors include: (i) lack of knowledge (e.g., limited familiarity and experiences of such projects among lenders and borrowers); and (ii) lack of demonstrated successes (e.g., project designs, deal flows, and business models for such investment

[41] Paragraph 36, 71, 88, 94: Clean Technology fund investment plant for Thailand, http://www.nesdb.go.th/Portals/0/home/interest/09/Final_Draft_CTF_InvestmentPlan_Oct09.pdf
[42] The Clean Technology Fund (CTF) invests in projects and programs that contribute to the demonstration, deployment and transfer of low carbon technologies with a significant potential for long-term greenhouse gas emissions savings. The CTF Trust Fund Committee oversees the operations of the Fund. The World Bank (IBRD) is the Trustee of the Fund.

projects have not yet been widely demonstrated). As a result financial institutions perceive lending to these projects as risky, resulting in higher costs of project development and debt financing.

Furthermore, the following instances reflect the views of two banks:

TMB Bank Public Co. Ltd (a major Thai bank) states "Access to financial resources and Low priority projects" as the major barriers faced by projects in the wastewater treatment sector[43].

Furthermore, the same view has been highlighted explicitly for the biogas projects by PROPARCO[44] (private sector financing arm of French Development Agency – AFD) as follows:

- High transaction cost – size rather small to attract commercial lenders
- New technologies, less experienced developers
- Capital intensive: projects extremely sensitive to the structure & conditions of capital cost financing
- High level of uncertainty – related to the level of activities of the host companies creates a difficult risk profile, including difficulty in guaranteeing cash flows

The issues highlighted above lead to a complicated and time-consuming process from lender's point of view.

It is therefore, clear that biogas project face sever access to finance barrier both from the point of view of a local commercial bank and development agencies and additional benefits from CDM play a crucial role in successful implementation of such projects.

Project-specific situation with regards to access to finance

(i) nature of company, organization and its ownership and, financial information

In reference to the Guidelines for objective demonstration and assessment of barrier, Annex 13, EB50, it is important to enhance the objectivity of the demonstration of additionality by providing quantitative approach to the demonstration of barrier. Point 4, Guideline 1 states that:

"While demonstrating barriers related to the lack of access to capital, information should include nature of company, organization and its ownership and, financial information".

The project proponent – "Maesod Biogas Company Limited" is a private limited company incorporated on 19th June 2008 with a registered capital of 1.25mTHB which was raised to 30 mTHB in 2009. The main business of the company is to implement biogas plant and generate power[45]. The ownership detail of the company will be provided to the DOE.

[43]Slide no - 6 and 7 http://www.google.co.th/url?sa=t&source=web&cd=9&ved=0CDwQFjAI&url=http%3A%2F%2Fwww.cd4cdm.org%2FAsia%2FFifth%2520Regional%2520Workshop%2FID%26developCDM-Thailand_Prapasawad.ppt&rct=j&q=financial%20barrier%20%2B%20clean%20technology%20%2B%20thailand&ei=cX6ETLmoNInksQOvvez2Bw&usg=AFQjCNG4YY-blMPmMvEg1Ud-sp9miPCNnQ&cad=rja

[44] Slide no – 9 and 10 http://www.setatwork.eu/events/thailand/25%20Paper/Working%20session%203.5_Proparco.pdf

[45] Company affidavit

As can be seen from the information about the company, it is classified under the SME category. The Thai government classifies SME[46] as a company having capitol not more than 200 million THB.

The project proponent applied for loan to various banks many of which showed interest initially. However, either the banks had very stringent conditions (high securities and interest rates) or simply refused to lend without giving a written refusal letter. The banks normally do not wish to provide written rejection letter but we have a rejection letter[47] from one bank as evidence. Nevertheless, the problem in securing loan faced by the project proponent is a problem faced by SMEs in Thailand. This can be verified by a detailed analysis provided by the Bank of Thailand's discussion paper on "*A Cross-Country Survey on SME Financial Access and implications for Thailand*"[48]. The paper clearly outlines barriers from SME's point of view and financial institution's perspective.

SME perspective: "*it has been reported that lack of information and advice from financial institutions, complexity and inconvenience related to loan application process, inadequate qualification of SMEs, expenses/fees and interest rates charged, and lack of collateral are the main obstacle to access to finance."*

Financial institution perspective: *" the main obstacles for lending to SMEs include the following factors: inadequate collateral; lack of business experience; inadequate management; unreliable accounting system; lack of business planning, firm's NPL history; high transaction and operational costs per SME loan application; strict government rules and regulations regarding loan lost provision and credit history in credit bureau."*

Referring back to the "Guidelines for objective demonstration and assessment of barrier" it is mentioned in Guideline 1:

"A company that is a subsidiary of a multinational group may have different access to capital, technologies or skilled labour than a local SME company."

The project proponent is not a subsidiary of a multinational group and clearly has a different access to capital due to its size and local financial environment.

The above discussion indicates the existence of **access to finance** barrier faced by the project proponent in an objective manner.

It should be noted that all the shareholders in the company were individual investors. The company falls under the SME category which makes it inherently difficult to secure loans as discussed above. The company specific financial details, ownership structure and the negative perception of this project type by financial institutions were available at the time of decision making. The project proponent was therefore already aware of difficulties in securing the finance for the project activity. This demonstrates that the barrier is real as per VVM v1.2 paragraph 117.

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[46] http://www.sme.go.th/cms/c/portal/layout?p_l_id=47.43

In English - http://www.smebank.co.th/whoissme_en.php

[47] Copy provided to the DOE.

[48] Page 2, 3 – section 2.2 Challenges in SME financing

http://www.bot.or.th/Thai/EconomicConditions/Publication/Documents/dp032010_SME.pdf

(ii) financial closure achievement through CDM and further background regarding time period between investment decision and loan approval / ERPA signature.

In April 2008, the project proponent had approached equity investor for a potential investment in the project activity. The investor[49] could not consider the investment in the project activity due to the fact the project activity will depend on the starch factory for its operation which was still not commissioned and the risk of investment in a new company would be very high. In May 2008, the project proponent requested for upfront financing from CDM revenues as a means to ensure financial feasibility and achieve financial closure of the project activity. This was reflected in the MoU[50] signed between the project proponent and the CDM consultant in May 2008. The project proponent continued to look for investors. The rejection letter from SCB bank in Dec 2008 shows that project proponent was in discussion with the banks well before the project's start date. The bank highlighted that loan was rejected due to financial situation of the company and more so since the starch factory was not commissioned. The audited balance sheet[51] for 2008 shows a paid up capital of only 1.25m THB which clearly shows weak financial situation of the company to interest any investor. Moreover, the banks are unwilling to consider the loan unless they see some amount of cash injection in the form of equity and certain amount of progress in the project. Already during the loan negotiation process with SCB (throughout 2008) and from parallel discussions with other investors, it was clear to the project owner that CDM revenues would be critical in securing a loan from a commercial bank by eventually decreasing the loan amount through carbon finance and by improving the financial feasibility of the project through additional CER revenues and therefore reducing the risk exposure of the bank.

In May 2009, TMB bank highlighted concerns in considering the loan for the project activity in an email[52] communication. The issues were mainly related to the un-acceptable shareholding structure in the project company and the fact that it was a new company with no back up by any parent company. The first ERPA and ENCOND fund contracts were signed on 8/6/2009 and 30/6/2009 respectively. The paid up capital (in the form of equity) into the project company was also raised from 1.25m to 30m THB in 2009 as per the audited balance sheet for 2009.

The contract with the technology provider was amended to its final form on 11/02/2009 and the security deposit to commence the work was only paid on 25/02/2009 (project start date). At that time, the shareholders of the project company felt confident enough that their efforts to secure CDM revenues and bridge the financing gap through alternative means of finance (i.e. carbon finance and ENCOND funds) would eventually succeed and decided to proceed with the initial instalment of 10% to the technology provides.

This represented the first significant expenditure for implementation of the project activity; no money was paid to technology provider in 2008. In 2009, only about 8mTHB[53] was spent on the project activity which represents only about 13% of the overall project cost. It should be noted that only when the project

[49] Letter from Investor submitted to DOE

[50] Copy of MoU submitted to DOE

[51] Submitted to DOE

[52] Email from TMB bank submitted to DOE

[53] As per payment summary from Technology supplier

activity achieved these critical milestones in terms of ERPA, approval of subsidy and construction start, the banks took real interest in considering the project activity.

As per the guideline 6 from the "Guidelines for objective demonstration and assessment of barrier" it is mentioned that:

> *"In case the PPs make the claim for investment barriers, they should demonstrate in the PDD that the financing of the project was assured only due to the benefit of the CDM."*

Due to lack of financing, some key components of the project like purchase of gas engine could not be procured in time and was eventually delayed. The project proponent continued to look for financing and managed to get a commitment for upfront financing from a CER buyer as pre-payment for expected CERs in early November 2010. The loan was finally approved by the bank on 24th November 2010. It is further noted that the bank considered CDM revenues crucial while approving the loan[54]. These two evidences (loan approval under consideration of CDM and CDM upfront payments to secure the remaining financing gap) clearly demonstrate objectively that CDM actually enabled financing of the project. Therefore, it is very clear that the project activity faced access to finance barrier throughout the project's progress. This also demonstrates the fact that like in any other investment, unless some amount of investment and or resources is pledged, no investor would be willing to invest in a new company. This also gave confidence to the project proponent that once some progress has been made in terms of project implementation and CDM application, it would be relatively easier to approach the banks and get the loan approved. Obviously this process takes time and the project proponent took a calculated risk to take a decision to invest in the project.

The above discussion demonstrates in an objective manner that the project activity faced access to finance barrier which was overcome only due to the additional benefits from CDM.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

The emission reductions from the methane avoidance component of the project activity are calculated as per the guidance given in the methodology (version 16 of AMS III.H). The emission reductions from thermal and electrical components are calculated as per the guidance given in the methodologies (version 19 of AMS I.C) and (version 17 of AMS I.D) respectively. The following sections outline in detail the methodological choices made for each component.

<u>Baseline emissions (BE_y)</u>

1: $BE_{CH4,y}$ - Baseline emissions for methane avoidance component (AMS III.H):

Baseline emissions for the systems affected by the project activity may consist of:

$$BE_{CH4,y} = \{BE_{power,y} + BE_{ww,treatment,y} + BE_{s,treatment,y} + BE_{ww,discharge,y} + BE_{s,final,y}\} \quad \textbf{Eq-1}$$

Where:

[54] Confirmation letter from the bank.

$BE_{CH4,y}$	Baseline emissions from methane avoidance component in year y (tCO_2e)
$BE_{power,y}$	Baseline emissions from electricity or fuel consumption in year y (tCO_2e)
$BE_{ww,treatment,y}$	Baseline emissions of the wastewater treatment systems affected by the project activity in year y (tCO_2e)
$BE_{s,treatment,y}$	Baseline emissions of the sludge treatment systems affected by the project activity in year y (tCO_2e)
$BE_{ww,discharge,y}$	Baseline methane emissions from degradable organic carbon in treated wastewater discharge into sea/river/lake in year y (tCO_2e).
$BE_{s,final,y}$	Baseline methane emissions from anaerobic decay of the final sludge produced in year y (tCO_2e).

1(a): $BE_{power,y}$ - Baseline emission from electricity and fuel consumptions

The baseline emissions from electricity consumption are not considered as the electricity consumption of the open anaerobic lagoons in the baseline scenario would be negligible. Furthermore, it is conservative to neglect this emission source. The baseline emissions from fuel consumption would be zero as no fossil fuels would have been consumed in the operation of the open anaerobic lagoons in the baseline scenario. Therefore, **$BE_{power,y}$** is assumed zero and removed from further consideration.

1(b): $BE_{ww,\ treatment,\ y}$ - Baseline emissions of the wastewater treatment systems affected by the project activity

Methane emissions from the baseline wastewater treatment systems affected by the project ($BE_{ww,treatment,y}$) are determined using the methane generation potential of the wastewater treatment systems as per the paragraph 20 of AMS III.H., version 16. The following equation is used.

$$BE_{ww,treatment,y} = \sum_i (Q_{ww,i,y} * COD_{inflow,i,y} * \eta_{COD,BL,i} * MCF_{ww,treatment,BL,i}) * B_{o,ww} * UF_{BL} * GWP_{CH4}$$

Eq-2

Where:

$Q_{ww,i,y}$	Volume of wastewater treated in baseline wastewater treatment system i in year y (m^3).
$COD_{inflow,i,y}$	Chemical oxygen demand of the wastewater inflow to the baseline treatment system i in year y (t/m3). This is same as $COD_{ww,\ untreated,y}$ as mentioned in the monitoring section B.7.1
$\eta_{COD,BL,i}$	COD removal efficiency of the baseline treatment system i
$MCF_{ww,treatment,BL,i}$	Methane correction factor for baseline wastewater treatment system i (MCF value as per table III.H.l).
i	Index for baseline wastewater treatment system.
$B_{o,ww}$	Methane producing capacity of the wastewater (IPCC value of 0.25 kg CH_4/kg COD)
UF_{BL}	Model correction factor to account for model uncertainties (0.89)[55]
GWP_{CH4}	Global Warming Potential for methane (value of 21)

As the baseline treatment system is different from the treatment system in the project scenario, the monitored values of COD inflow ($COD_{ww,untreated,y}$) during the crediting period will be used to calculate the baseline emissions ex-post.

[55] Reference: FCCC/SBSTA/2003/10/Add.2, page 25.

The COD removal efficiency of the baseline system has been measured ex-ante through measurement campaign as per paragraph 28-2(a). Please refer to section B.4. and Annex 3 for more details.

1(c): $BE_{s,\ treatment,\ y}$ - Baseline emissions of the sludge treatment systems affected by the project activity

There is no baseline sludge treatment system. Therefore, this baseline emission source is excluded from further consideration.

1(d): $BE_{s,\ final,\ y}$ – Baseline methane emissions from anaerobic decay of the final sludge produced

The project activity is implemented at a Greenfield location. The baseline treatment system would not have generated any sludge. Therefore, this baseline emission source is excluded from further consideration. Furthermore, the exclusion of this emission source is conservative.

1(e): $BE_{ww,\ discharge,\ y}$ - Baseline methane emissions from degradable organic carbon in treated wastewater discharged into sea/river/lake

In the baseline treatment system the wastewater is not discharged into a sea/lake/river, therefore this baseline emission source is excluded from further consideration.

Therefore, the baseline emissions from methane avoidance component applicable to the project activity are given as:

$$BE_{CH4,y} = BE_{ww,treatment,y} \qquad \textbf{Eq-3}$$

2: $BE_{thermal,CO2,y}$ - Baseline emission for Thermal displacement component: (AMS I.C)

As per AMS.I.C, paragraph 22, for heat[56] produced using fossil fuels the baseline emissions are calculated as follows:

$$BE_{thermal,CO_2,y} = (EG_{thermal,y} / \eta_{BL,thermal}) * EF_{BL,FF,CO_2} \qquad \textbf{Eq-4}$$

Where:

$BE_{thermal,CO_2,y}$	The baseline emissions from steam/heat displaced by the project activity during the year y (tCO_2)
$EG_{thermal,y}$	The net quantity of heat supplied by the project activity during the year y (TJ)
EF_{BL,FF,CO_2}	The CO_2 emission factor of the fossil fuel that would have been used in the baseline plant, obtained from reliable local or national data if available, alternatively, IPCC default emission factors can be used tCO_2 / TJ
$\eta_{BL,thermal}$	The efficiency of the plant using fossil fuel that would have been used in the absence of the project activity

During ex-post estimation, $EG_{thermal,y}$ is calculated as follows:

[56] The biogas will be utilised partly in the thermal boiler to generate heat.

$$EG_{thermal,y} = Q_{oil,y} \cdot \rho_{oil,avg} \cdot (T_{out} - T_{in}) \cdot LHC_{oil,avg} \cdot \frac{4.184}{10^9}$$

Where:

$EG_{thermal,y}$	The net quantity of heat supplied by the project activity during the year *y* (TJ)
$Q_{oil,y}$	Quantity of the thermic fluid from boiler to the process plant (m3)
T_{out}	Temperature of thermic fluid leaving the boiler for heat transfer (deg C)
T_{in}	Temperature of thermic fluid entering the boiler after heat transfer (deg C)
LHC_{oil}	Average liquid head capacity (cal/g-^oC)
$\rho_{oil,avg}$	Average density of thermic fluid (kg/m3)

3: $BE_{elec,y}$ - Baseline emission for Electricity generation component: (AMS I.D)

As per AMS I. D., paragraph 11, the baseline is the MWh produced by the renewable generating unit multiplied by an emission coefficient as follows:

$$BE_{elec,y} = EG_{BL,y} * EF_{CO2,grid,y} \quad \textbf{Eq-5}$$

Where:

$BE_{elec,y}$	Baseline emissions from electricity generation in year y (tCO_2e).
$EG_{BL,y}$	Quantity of electricity generated and exported to the grid by the project activity during the year *y* (MWh)
$EF_{CO2,grid,y}$	Thailand National Grid emission factor (tCO_{2e}/MWh)

Project emissions (PE_y)

4: Project activity emission for methane avoidance component (AMS III.H):

Project activity emissions from the systems affected by the project activity are:

(i) CO_2 emissions on account of power and fuel used by the project activity facilities ($PE_{power, y}$);
(ii) Methane emissions from wastewater treatment systems affected by the project activity, and not equipped with biogas recovery in the project situation ($PE_{ww, treatment, y}$);
(iii) Methane emissions from sludge treatment systems affected by the project activity, and not equipped with biogas recovery in the project situation ($PE_{s, treatment, y}$);
(iv) Methane emissions on account of inefficiency of the project activity wastewater treatment systems and presence of degradable organic carbon in treated wastewater ($PE_{ww, discharge, y}$);
(v) Methane emissions from the decay of the final sludge generated by the project activity treatment systems ($PE_{s, final, y}$);
(vi) Methane fugitive emissions on account of inefficiencies in capture systems ($PE_{fugitive, y}$);
(vii) Methane emissions due to incomplete flaring ($PE_{flaring, y}$);
(viii) Methane emissions from biomass stored under anaerobic conditions which would not have occurred in the baseline situation ($PE_{biomass,y}$).

$$PE_{CH4,y} = \begin{Bmatrix} PE_{power,y} + PE_{ww,treatment,y} + PE_{s,treatment,y} + PE_{ww,discharge,y} + PE_{s,final,y} + \\ PE_{fugitive,y} + PE_{biomass,y} + PE_{flaring,y} \end{Bmatrix} \quad \textbf{Eq-6}$$

Where:

$PE_{CH4,y}$	Project activity emissions in the year *y* (tCO_2e)
$PE_{power,y}$	Emissions from electricity or fuel consumption in the year *y* (tCO_2e). These emissions shall be calculated as per paragraph 19, for the situation of the project scenario, using energy consumption data of all equipment/devices used in the project activity wastewater and sludge treatment systems and systems for biogas recovery and flaring/gainful use
$PE_{ww, treatment, y}$	Emissions from electricity or fuel consumption in the year *y* (tCO_2e). These emissions shall be calculated as per paragraph 19, for the situation of the project scenario, using energy consumption data of all equipment/devices used in the project activity wastewater and sludge treatment systems and systems for biogas recovery and flaring/gainful use
$PE_{s, treatment, y}$	Methane emissions from sludge treatment systems affected by the project activity, and not equipped with biogas recovery, in year *y* (tCO_2e).
$PE_{ww, discharge, y}$	Methane emissions from degradable organic carbon in treated wastewater in year *y* (tCO_2e).
$PE_{s, final, y}$	Methane emissions from anaerobic decay of the final sludge produced in year *y* (tCO_2e).
$PE_{fugitive, y}$	Methane emissions from biogas release in capture systems in year *y*, calculated as per paragraph 30 (tCO_2e)
$PE_{flaring,y}$	Methane emission due to incomplete flaring in year *y* (tCO_2e)
$PE_{biomass, y}$	Methane emissions from biomass stored under anaerobic conditions

4(a): $PE_{power, y}$ - Emissions from electricity consumption

Project emissions due to electricity consumption attributed to the project activity, can be calculated based on two different approaches. The first approach is based on paragraph 19 of the methodology, whereas $PE_{power,y}$ shall be estimated according to the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption". The second approach is based on the monitoring section of AMS.III.H Version 16, paragraph 37, monitoring parameter No. 9, whereas a simpler approach based on a conservative estimation of electricity consumption using the rated capacity of auxiliary equipment is suggested as alternative. This second approach is more conservative than the first one (based on actual measurement of electricity consumption in the project) and shall be used as a backup option for ex-post emission reduction calculation in case of non-availability or problems with monitoring data for electricity consumption measurement.

i. *Calculation of $PE_{power,y}$ as per "Tool to calculate baseline, project and/or leakage emissions from electricity consumption":*

The *Scenario A: Electricity consumption from the grid* will be applied to the project activity for the amount of electricity imported from the grid. The generic approach is used to calculate the project emissions as follows:

$$PE_{power,y} = \sum EC_{PJ,j,y} \times EF_{EL,j,y} \times (1 + TDL_{j,y}) \qquad \textbf{Eq-7}$$

Where:

$PE_{power,y}$ Project emissions from electricity consumption in year y (tCO_2)

$EC_{PJ,j,y}$	Quantity of electricity consumed by the project electricity consumption source j in year y (MWh)
$EF_{EL,j,y}$	Emission factor for electricity generation source j in year y (tCO_2/MWh)
$TDL_{j,y}$	Average technical transmission and distribution losses for providing electricity to source j in year y. A default value of 20% shall be assumed as conservative assumption as per applied tool.
j	Source of electricity consumption in the project

Determination of emission factor for the electricity generation ($EF_{EL,j,y}$)
Option A1 has been used to determine emission factor. This option proposes to calculate the combined margin emission factor of the applicable electricity system, using the procedures in the latest approved version of the "Tool to calculate the emission factor for an electricity system, version 02.2.0" ($EF_{EL,j,y} = EF_{CO2,grid,y}$). The grid emission factor details are further explained in Annex 3.

Determination of average technical transmission and distribution losses
$TDL_{j,y}$ will be taken from the recent data available within the host country.

ii. *Calculation of $P_{power,y}$ as per AMS.III.H Version 16, paragraph 37, monitoring parameter No. 9:*

As mentioned above this alternative approach shall be used mainly for ex-post emission reduction calculation only in cases of non-availability or problems with monitoring data for electricity consumption measurement required for the first approach described above. Under these circumstances, $PE_{Power,y}$ shall be calculated as follows:

It is assumed that all relevant electrical equipment operate at full rated capacity, plus 10% to account for distribution losses, for 8760 hours per annum using the following equation:

$$PE_{power,exante} = \frac{\sum P_{el} * 110\% * 8,760 * EF_{CO2.grid,y}}{1000} \quad \textbf{Eq-8}$$

Where:

$PE_{power,exante}$	Emissions from electricity consumption in the project activity, (tCO2)
P_{el}	Total installed electrical capacity of the equipments in the project activity (kW)
$EF_{CO2,grid,y}$	Thailand National Grid emission factor (tCO_{2e}/MWh)

4(b): $PE_{ww,treatment,\ y}$ - Emissions from wastewater treatment systems affected by the project activity, and not equipped with biogas recovery in the project situation.
This emission source is applicable to the open lagoons which will be used as a secondary treatment option for the wastewater treated in the project activity. The same is calculated as per paragraph 20 in the methodology:

$$PE_{ww,treatment,y} = \sum (Q_{ww,k,y} * COD_{inflow,k,y} * \eta_{COD,PJ,k} * MCF_{ww,treatment,PJ,k}) * B_{o,ww} * UF_{PJ} * GWP_{CH4}$$

Eq-9

Where;

$Q_{ww,k,y}$	Volume of wastewater treated in system affected by the project activity in year y (m^3)
GWP_{CH4}	Global Warming Potential for methane (value of 21 is used)

$B_{o, ww}$	Methane producing capacity of the wastewater (IPCC default value of 0.25 kg CH_4/kg COD)
$COD_{inflow,k,y}$	Chemical oxygen demand of the wastewater inflow to the project treatment system k in year y (t/m3). This is same as $COD_{ww,treated,y}$ as mentioned in monitoring section B.7.1.
$\eta_{COD,PJ,k}$	Chemical oxygen demand removal efficiency of the project wastewater treatment system k in year y
$MCF_{ww,treatment,PJ,k}$	Methane correction factor for project wastewater treatment system k without biogas recovery.
UF_{PJ}	Model correction factor to account for model uncertainties (1.12)

It should be noted that $Q_{ww,k,y} = Q_{ww,i,y}$

4(c): $PE_{s,treatment,y}$ - Methane emissions from sludge treatment systems affected by the project activity, and not equipped with biogas recovery.
There is no sludge treatment system prior to the implementation of the project activity. Therefore, this parameter is not applicable in the calculations and has been excluded from further consideration.

4(d): $PE_{ww,discharge,y}$ - Methane emissions from degradable organic carbon in treated wastewater.
In the project activity, the treated wastewater will not be discharged into to a river, sea or lake. Therefore, project emissions from this component have not been included in the assessment.

4(e): $PE_{s,final,y}$ - Emissions from anaerobic decay of the final sludge produced
It is not expected that the project activity will generate significant amount of sludge. The excess sludge may be used for starting up other systems equipped with biogas recovery or for soil application under aerobic conditions. Therefore, as per the methodology paragraph 29, this term is neglected ex-ante.

The final disposal of sludge shall be monitored during the crediting period. In case the application of sludge cannot be monitored, as a conservative measure, it will be assumed that the sludge removed would have decayed in anaerobic manner. The emissions will be accounted as per equation 7 in paragraph 25 of the methodology.

4(f): $PE_{, fugitive\ y}$ - Emissions on account of inefficiencies in capture systems
Project activity emissions from methane release in capture systems are determined as per paragraph 30 of AMS III.H as follows:

$$PE_{fugitive,y} = PE_{fugitive,ww,y} + PE_{fugitive,s,y} \qquad \textbf{Eq-10}$$

Where;

$PE_{fugitive, ww, y}$	Fugitive emissions through capture inefficiencies in the anaerobic wastewater treatment in the year y (tCO_{2e})
$PE_{fugitive, s,y}$	Fugitive emissions through capture inefficiencies in the anaerobic sludge treatment systems in the year y (tCO2e)

$PE_{fugitive,ww, y}$
These emissions are calculated as follows:

$$PE_{fugitive,ww,y} = (1 - CFE_{ww}) * MEP_{ww,treatment,y} * GWP_{CH4} \qquad \textbf{Eq-11}$$

Where;

CFE_{ww}	Capture efficiency of the biogas recovery equipment in the wastewater treatment systems (a default value of 0.9 shall be used)
$MEP_{ww, treatment,y}$	Methane emission potential of wastewater treatment systems equipped with biogas recovery system in year *y* (t)

Further,

$$MEP_{ww,treatment,y} = Q_{ww,y} * B_{o,ww} * UF_{PJ} * \sum_{k} COD_{removed,PJ,k,y} * MCF_{ww,treatment,PJ,k} \quad \textbf{Eq-12}$$

Where;

$COD_{removed,PJ,k,y}$	The chemical oxygen demand removed[57] by the treatment system *k* of the project activity equipped with biogas recovery in the year *y* (t/m^3). This is equal to $COD_{ww,untreated,y} – COD_{ww,treated,y}$
$MCF_{ww, treatment,PJ,k}$	Methane correction factor for the project wastewater treatment system *k* equipped with biogas recovery equipment (MCF values as per Table III.H.1)
$B_{o, ww}$	Methane producing capacity of the wastewater (IPCC default value of 0.25 kg CH_4/kg COD)
UF_{PJ}	Model correction factor to account for model uncertainties (1.12)

$PE_{fugitive,s, y}$

There is no anaerobic sludge treatment in the project activity. Therefore, this source of emissions is excluded from further consideration.

Thus, the fugitive emissions through capture inefficiencies in the anaerobic wastewater treatment systems are given as:

$$PE_{fugitive,y} = PE_{fugitive,ww,y} \quad \textbf{Eq-13}$$

4(g): $PE_{flaring\ y}$ - Methane emissions due to incomplete flaring

Step1 - Determination of the mass flow rate of the residual gas that is flared

This step calculates the residual gas mass flow rate in each hour h, based on the volumetric flow rate and the density of the residual gas. The density of the residual gas is determined based on the volumetric fraction of all components in the gas. As per the guidance of the tool, a simplified approach will be used and only the volumetric fraction of methane will be measured, the difference is considered to be 100% Nitrogen.

STEP 2 though STEP 4 are not applicable for this project.

STEP 5: Determination of methane mass flow rate in the residual gas on a dry basis

The quantity of methane in the residual gas flowing into the flare is the product of the volumetric flow rate of the residual gas ($FV_{RG,h}$), the volumetric fraction of methane in the residual gas ($fv_{CH4,RG,h}$) and the density of methane ($\rho_{CH\ 4,n}$) in the same reference conditions (normal conditions and dry or wet basis).

57 Difference between the inflow COD and the outflow COD.

Considering that the gas is cooler than 60 degrees Celsius, the reported density is expressed on dry basis already.

$$TM_{RG,h} = FV_{RG,h} * fv_{CH4,RG,h} * \rho_{CH4,n} \qquad \textbf{Eq-14}$$

Where:

$TM_{RG,h}$	Mass flow rate of methane in the residual gas in the hour h (kg/h)
$FV_{RG,h}$	Volumetric flow rate of the residual gas in dry basis at normal conditions in hour h (m^3/h)
$fv_{CH4, RG,h}$	Volumetric fraction of methane in the residual gas on dry basis in hour h
$\rho_{CH4,n}$	Density of methane at normal condition (0.716 kg/m3)

As per Step 6 of the flaring tool for determination of the hourly flare efficiency, a default value of 90% will be used, provided the flare is operational. The following guidance as per step 6 will be used:

- 0% if the temperature in the exhaust gas of the flare (T_{flare}) is below 500°C for more than 20 minutes during the hour h.
- 50%, if the temperature in the exhaust gas of the flare (T_{flare}) is above 500 °C for more than 40 minutes during the hour h, but the manufacturer's specifications on proper operation of the flare are not met at any point in time during the hour h.
- 90%, if the temperature in the exhaust gas of the flare (T_{flare}) is above 500 °C for more than 40 minutes during the hour h and the manufacturer's specifications on proper operation of the flare are met continuously during the hour h.

According to step 7 annual project emissions from flaring are calculated as the sum of emissions from each hour h, based on the methane flow rate in the residual gas ($TM_{RG,h}$) and the flare efficiency during each hour h ($\eta_{flare, h}$), as follows:

$$PE_{flare,y} = \sum_{h=1}^{8760} TM_{RG,h} * (1 - \eta_{flare-h}) * GWP_{CH4} / 1000 \qquad \textbf{Eq-15}$$

$TM_{RG,h}$	Mass flow rate of methane in the residual gas in the hour h (kg/h)
$\eta_{flare-h}$	Flare efficiency in hour h
GWP_{CH4}	Global Warming Potential of methane valid for the commitment period (tCO_2e/tCH_4)

4(h): PE $_{biomass, y}$ - Methane emissions from biomass stored under anaerobic conditions

There is no biomass storage in the project activity. Therefore, this source of emissions has been excluded from further consideration.

5: Project emission for Thermal displacement component: (AMS I.C)

As per AMS I. C., paragraph 45, CO_2 emissions from on-site consumption of fossil fuels due to the project activity shall be calculated using the latest version of "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion". Although the project activity is expected to generate sufficient biogas which can replace 100% of fuel oil in the boiler, usage of fuel oil cannot be ruled out completely

during biogas shortage or shut-down period. Therefore, CO2 emissions from fossil fuel consumption in the boiler are calculated as:

$$PE_{boiler,y} = FC_{k,y} \cdot NCV_{k,y} \cdot EF_{CO2,k,y}$$ **Eq-16**

Where:

$FC_{k,y}$	Quantity of fossil fuel type k combusted in the thermal oil boiler during the year y (mass or volume unit/yr);
$NCV_{k,y}$	Net calorific value of fossil fuel type k, GJ/mass or volume unit)
$EF_{CO2,k,y}$	CO_2 emission factor of fuel type k in the year y (tCO_2/GJ)

6: Project emission for Electricity generation component: (AMS I.D)

As per AMS I. D., paragraph 20, for the most renewable energy project activity, PE_y = 0. The project emission under AMS I.D are considered zero.

Leakage emissions (LE_y)

The project activity is not using equipment transferred from another activity; therefore there is no leakage to be considered.

Emissions reductions (ER_y)

(1) Emission reductions from the methane avoidance component of the project activity $ER_{CH4,y}$

As per the guidance given in the paragraph 33 of AMS III.H, *ex post* emission reductions shall be based on the lowest value of the following:

(i) The amount of biogas recovered and fuelled or flared (*MDy*) during the crediting period, that is monitored *ex post*;
(ii) *Ex post* calculated baseline, project and leakage emissions based on actual monitored data for the project activity.

Therefore, as per paragraph 34,

$$ER_{CH4,y} = \min\begin{pmatrix} (BE_{CH4,y} - PE_{EC,y} - PE_{ww,treatment,y} - PE_{fugitive,y} - PE_{flare,y}), \\ (MD_y - PE_{EC,y}) \end{pmatrix}$$ **Eq-17**

As per paragraph 35 in AMS III.H., *In the case of flaring/combustion MD_y will be measured using the conditions of the flaring and combustion process:*

$$MD_y = W_{CH4} * D_{CH4} * GWP_{CH4} * [(BG_{flare,y} * FE) + (BG_{combusted,y} * DE)]$$ **Eq-18**

Where:

$w_{CH4,y}$	Methane content of the biogas in the year *y* (volume fraction)

D_{CH4}	Density of methane at the temperature and pressure of the biogas in the year *y* (tonnes/m^3)
GWP_{CH4}	Global warming potential of methane, 21
$BG_{flare,y}$	Amount of biogas flared during the year y, Nm^3/year
$BG_{combusted,y}$	Biogas combusted for gainful use in year *y* (Nm^3/year)
FE	Flare efficiency (fraction)
DE	Destruction efficiency of biogas combusted for a gainful use (100%)

(2) Emission Reduction from the methane avoidance, thermal and electrical component (ER_y)
From equations 4,5 and 17, the total emission reductions from the project activity are given as:

$$ER_y = ER_{CH4,y} + BE_{thermal,CO2,y} + BE_{elec,y} \qquad \textbf{Eq-}19$$

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	**GWP_{CH4}**
Data unit:	-
Description:	Global warning potential of methane gas
Source of data used:	AMS.III.H
Value applied:	21
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value.
Any comment:	-

Data / Parameter:	**$B_{o,ww}$**
Data unit:	kg CH_4/kg COD
Description:	Methane generation capacity of COD in wastewater.
Source of data used:	IPCC default value, as per methodology AMS III.H
Value applied:	0.25 kg CH_4/kg COD
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value
Any comment:	-

Data / Parameter:	**UF_{BL}**
Data unit:	-
Description:	Model correction factor to account of model uncertainties (baseline emissions calculation)

Source of data used:	AMS.III.H, version 16
Value applied:	0.89
Justification of the choice of data or description of measurement methods and procedures actually applied :	
Any comment:	-

Data / Parameter:	**UF_{PJ}**
Data unit:	-
Description:	Model correction factor to account for model uncertainties (project emissions calculation)
Source of data used:	AMS III.H., Version 16
Value applied:	1.12
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	-

Data / Parameter:	**$MCF_{ww, treatment,BL,i}$**
Data unit:	-
Description:	Methane correction factor for the baseline anaerobic wastewater treatment systems
Source of data used:	Table III.H.1 from AMS-III.H, Version 16 , IPCC default values
Value applied:	0.8
Justification of the choice of data or description of measurement methods and procedures actually applied :	The baseline wastewater treatment system consists of a succession of anaerobic deep lagoons (depth more than 2 metres) therefore the MCF value is chosen as 0.8
Any comment:	IPCC Default values from chapter 6 of volume 5 page no 6.21. Waste in 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

Data / Parameter:	**$MCF_{ww, treatment,PJ,k}$**
Data unit:	-
Description:	Methane correction factor for project wastewater treatment system k
Source of data used:	Table III.H.1 from AMS-III.H, Version 16, IPCC default values
Value applied:	0.8
Justification of the choice of data or description of	In the project scenario the post treatment of wastewater treatment system without biogas recovery consists of a succession of lagoons, with depth greater than 2 metres, thus the value of 0.8 has been chosen.

measurement methods and procedures actually applied :	
Any comment:	IPCC Default values from chapter 6 of volume 5 page no 6.21. Waste in 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

Data / Parameter:	**CFE_{ww}**
Data unit:	Fraction
Description:	Capture efficiency of the biogas recovery equipment in the wastewater treatment
Source of data used:	AMS III.H
Value applied:	0.9
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value as per AMS III.H.
Any comment:	-

Data / Parameter:	$\eta_{COD,BL,i}$
Data unit:	%
Description:	COD removal efficiency of the baseline system i
Source of data used:	Measurement campaign in the baseline wastewater system for 10 days
Value applied:	88.17% - Used for ex-ante estimation of baseline emissions.
Justification of the choice of data or description of measurement methods and procedures actually applied :	The COD removal efficiency value is based on COD campaign data and multiplied by a factor of 0.89 to account of uncertainty range due to data from the campaign measurement in the referenced plant. This is in line with the AMS III.H given in paragraph 28 (2.a) which requires a measurement campaign in the comparable exiting wastewater treatment plant for the Greenfield project. The campaign was conducted by an external laboratory and further details are provided in Annex 3.
Any comment:	-

Data / Parameter:	$\rho_{CH4,n}$
Data unit:	kg/m^3
Description:	Density of methane at normal conditions
Source of data used:	Tool to determine project emissions from flaring gases containing methane
Value applied:	0.716
Justification of the choice of data or description of measurement methods and procedures actually applied :	CDM EB as per EB28 Meeting report (Annex 13).
Any comment:	

Data / Parameter:	**$EF_{CO2,grid,y}$**
Data unit:	tCO_2/MWh
Description:	CO_2 emission factor for grid power
Source of data used:	DEDE and other publicly available sources in Thailand (please refer to Annex 3)
Value applied:	0.53 – fixed ex-ante
Justification of the choice of data or description of measurement methods and procedures actually applied :	The emission factor is calculated according to the "Tool to calculate the emission factor for an electricity system" (version 02.2.0). The choice of data has been detailed in Annex-3.
Any comment:	Detailed calculation in Annex-3

Data / Parameter:	**$EF_{BL,FF,CO2}$**
Data unit:	tCO_2/TJ
Description:	The CO_2 emission factor of the fossil fuel that would have been used in the baseline plant; tCO_2 / TJ
Source of data used:	2006 IPCC
Value applied:	77.40 – fuel oil (as per baseline demonstration in section B.4) – fixed ex-ante
Justification of the choice of data or description of measurement methods and procedures actually applied :	The IPCC default value of the CO_2 emission factor of fuel oil is applied as per Table 1.4, "Default CO2 emission factor for combustion" (IPCC 2006, volume 2-chapter 1). Local values are not available.
Any comment:	-

Data / Parameter:	ρ_{FO}
Data unit:	Kg/m3
Description:	Density of fossil fuel combusted in the thermal boiler
Source of data used:	Thai local value (PTT)
Value applied:	0.95 – fixed ex-ante
Justification of the choice of data or description of measurement methods and procedures actually applied :	http://www.pttplc.com/Files/Document/Pdf/energy/nc_en_ee-01_01.pdf
Any comment:	-

Data / Parameter:	DE
Data unit:	%
Description:	Destruction efficiency of the electricity generator
Source of data used:	Default value, paragraph 35 AMS III.H

Value applied:	100%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value based on guidance given in paragraph 35 of AMS III.H.
Any comment:	–

Data / Parameter:	$\eta_{BL,thermal}$
Data unit:	%
Description:	Efficiency of the thermal oil boiler in the baseline
Source of data used:	Default value as per option F in "Tool to determine the baseline efficiency of thermal or electric energy generation systems"
Value applied:	–100%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Default value based on guidance given in "Tool to determine the baseline efficiency of thermal or electric energy generation systems"
Any comment:	Fixed ex-ante

B.6.3 Ex-ante calculation of emission reductions:

Baseline emissions (BE_y)
The ex-ante estimation of the baseline emissions can be given as per the equations 3, 4 and 5 in section B.6.1.

$$BE_y = BE_{CH4,y} + BE_{thermal,CO2,y} + BE_{elec,y}$$ **Eq-20**

Where:

$$BE_{CH4,y} = BE_{ww,treatment,y}$$

$$BE_{thermal,CO_2,y} = (EG_{thermal,y} / \eta_{BL,thermal}) * EF_{BL,FF,CO_2}$$

$$BE_{elec,y} = EG_{BL,y} * EF_{CO2,grid,y}$$

The following section gives details of ex–ante estimation of baseline emissions:

Methodology: AMS III H (Methane avoidance component)
Formula:

$BE_{ww,treatment,y} = \sum_i (Q_{ww,i,y} * COD_{inflow,i,y} * \eta_{COD,BL,i} * MCF_{ww,treatment,BL,i}) * B_{o,ww} * UF_{BL} * GWP_{CH4}$		
$Q_{y, ww}$	1,134,000 m3	Based on the initial assumptions made by the technology provider
$COD_{inflow,i,y}$	0.01505t/m3	Based on the measurement campaign in the proposed baseline of the referenced wastewater system plant. Please refer to Annex 3.
$\eta_{CO2,BL,i}$	88.2%	Please refer to Annex3.
$B_{o, ww}$	0.25kg CH_4/kg COD	Default value
$MCF_{ww, treatment, i}$	0.8	Default value for anaerobic deep lagoons (as per table III.H.1 of AMS III.H)
GWP_{CH4}	21	Default value
UF_{BL}	0.89	Model correction factor from AMS III. H.
Calculation: $BE_{CH4,y} = BE_{ww,treatment,y}$ = 1,134,000 X 0.01505 X 88.2% X 0.25 X 0.8 X 21 X 0.89 = 56,261.33 tCO2		
Methodology: AMS I.C. (Thermal displacement component)		
Formula: $BE_{thermal,CO_2,y} = (EG_{thermal,y} / \eta_{BL,thermal}) * EF_{FF,CO_2}$		
$EG_{thermal,y} =$	94.89 TJ	Based on the rated capacity of the boiler as 3,500,000 kcal/hour and assuming 270 days of operation. Detailed calculations are provided in the calculation spreadsheet[58].
$EF_{FF,CO_2} =$	77.40 tCO2/TJ	For fuel oil – 2006 IPCC.
$\eta_{BL,thermal} =$	100%	Default value
Calculation: $BE_{thermal,CO_2,y}$ = (94.89/100%) X 77.40 = **7,344.73 tCO_2e**		
Methodology: AMS I.D (Electricity generation component)		
Formula: $BE_{elec,y} = EG_{BL,y} * EF_{CO2,grid,y}$		
$EG_{BL, y}$ =	6,078.24 MWh	Based on the net output from gas engine as 938kW and 270 days of operation.
$EG_{BL,y}$	6,602.11 MWh	Based on 2.28 kWh/m3 conversion ratio assumed by the technology provider and 2,895,663m3 of biogas sent to the gas engine.
EF_y =	0.53 tCO2/MWh	Please refer to Annex 3
Calculation: $BE_{elec,y}$ = MIN(6078.24 , 6602.11) X 0.53 = **3,221.47 tCO2e** *(ex-post estimate will be based only on the metered electricity in line with AMS-I.D and monitoring plan in PDD section B.7.1)*		

It should be noted that ex-post baseline emissions will be calculated as per the equations provided in section B.6.1.

[58] During actual project operation, the parameter will be calculated based on the temperature (in and out) from the thermal oil boiler and the amount of thermic fluid circulated. These are included in the monitoring section.

Project emissions (PE_y):

The ex-ante estimation of the project emissions can be given as per the equations 8,9,11,15 and 16 given in section B.6.1.

$$PE_y = PE_{power,exante} + PE_{ww,treatment,y} + PE_{fugitive,y} + PE_{flare,y} + PE_{boiler,y} \quad \textbf{Eq-21}$$

As already mentioned in section B.6.1, there are no project emissions from the electrical component (AMS.I.D) of the project activity. The emissions if any from the fossil fuel used in the boiler (AMS.I.C) will be accounted ex-post. Therefore, the project emissions are only from the methane avoidance component of the project activity as given in the equation above.

The following section gives details of ex – ante estimation of project emissions:

Methodology: AMS III.H (Methane avoidance component)		
Emission from electricity consumption		
Formula: $PE_{power,y} = \sum EC_{PJ,j,y} \times EF_{EL,j,y} \times (1 + TDL_{j,y})$		
$E_{PJ,j,y}$ =	729.972 MWh	Power rating based on the list given by technology provider and 6480 hours of operations.
$EF_{EL,j,y}$ =	0.53 tCO2/MWh	Please refer to Annex 3
$TDL_{j,y}$	5.9%	Annual report published by DEDE and Ministry of Energy, Thailand
Calculation: $PE_{power,y}$ = 409.71 tCO2e (detailed ex-ante calculation given the calculation sheet)		
Emissions in wastewater treatment system without biogas recovery		
Formula: $PE_{ww,treatment,y} = \sum (Q_{ww,k,y} * COD_{inflow,k,y} * \eta_{COD,PJ,k} * MCF_{ww,treatment,PJ,k}) * B_{o,ww} * UF_{PJ} * GWP_{CH4}$		
$Q_{ww,k,y}$ =	1,134,000 m3	Based on the initial assumptions made by the technology provider
$COD_{inflow,k,y}$ =	0.00075t/m3	Based on COD out by project's biogas (this is conservative.)
$\eta_{COD,PJ,k}$	99.07%	Taken from COD campaign as per Annex 3. This is conservative.
$B_{o,ww}$ =	0.25kg CH_4/kg COD	Default value as per AMS III.H.
$MCF_{ww,treatment,i}$ =	0.8	Default value as per Table III.H.1 of AMS III.H.
GWP_{CH4} =	21	Default value as per AMS III.H
UF_{PJ}	1.12	Default value as per AMS III.H
Calculation: $PE_{ww,treatment,y}$ = 1,134,000 X 0.00075 X 99.07% X 0.25 X 0.8 X 21 X 1.12 = **3,978 tCO_2 e**		
Fugitive emissions in wastewater treatment system with biogas recovery		

Formula: $PE_{fugitive,ww,y} = (1 - CFE_{ww}) * MEP_{ww,treatment,y} * GWP_{CH4}$		
CFE_{ww}	0.9	Default value as per AMS III.H
$MEP_{ww, treatment,y}$	3,633 tCH4/year	Detailed calculations are available in the calculation sheet.
Calculation: $PE_{fugitive,ww,y}$ = (1-0.9) X 3,633 x 21 = **7,628 tCO_2 e**		
Methane emissions due to incomplete flaring		
Formula: $PE_{flare,y} = \sum_{h=1}^{8760} TM_{RG,h} * (1 - \eta_{flare-h}) * GWP_{CH4} / 1000$		
Calculation: $PE_{flare,y}$ - It is not possible to estimate the amount of biogas which will be flared as this would happen only in the case of emergencies or surplus. However as a conservative measure, ex-ante electricity generation based on rated net output of gas engine was taken as the lower value compared to electricity generation based on biogas volume, some biogas is surplus which may be flared. This is equal to 229,768.29 m3 per year[59]. Using default flare efficiency as 90%, methane content in biogas as 65%, GWP of methane as 21 and methane density as 0.716kg/m3, project emissions from flaring are given as Where: $TM_{RG,h}$ = 229,768.29 m3 * 65% * 0.716 = 106,943.16 kg of methane $PE_{flare,y}$=106,943.16 * (1-90%) * 21 / 1000 = 224.56 tCO2e.		
Methodology: AMS I.C (Thermal displacement component)		
Emission from on-site consumption of fossil fuels due to the project activity		
Formula: $PE_{boiler,y} = FC_{k,y} \cdot NCV_{k,y} \cdot EF_{CO2,k,y}$		
$FC_{k,y}$ =	0 ton	For ex-ante quantity of fuel oil combusted in the thermal oil boiler is assumed as zero. The project activity is expected to displace 100% of fuel oil in the boiler.
$NCV_{k,y}$ =	40.4 GJ/ton	For fuel oil-IPCC value
$EF_{CO2,k,y}$=	77.40 tCO2/MWh	For fuel oil-IPCC value
Calculation: $PE_{boiler,y}$ = 0 tCO2e (detailed calculation given the calculation sheet)		

It should be noted that $Q_{ww,k,y} = Q_{ww,i,y}$

Emission Reduction Summary:

To summarise ex-ante baseline and project emissions are given as follows:

59 Please refer to the XL sheet for more details.

As per equation 20, total baseline emissions are given as:

BE_y = 66,828 tCO2/year

As per equation 21, the total project emissions are given as:

PE_y = 12,240 tCO2/year

Therefore, the ex-ante estimates on emissions reductions are given as:

ER_y = 54,587 tCO2/year

B.6.4 Summary of the ex-ante estimation of emission reductions:

AMS.III.H (Methane Avoidance Component)

Year	Emission of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)
2011	12,240	56,261	-	44,021
2012	12,240	56,261	-	44,021
2013	12,240	56,261	-	44,021
2014	12,240	56,261	-	44,021
2015	12,240	56,261	-	44,021
2016	12,240	56,261	-	44,021
2017	12,240	56,261	-	44,021
Total (tonnes CO_2e)	85,681	393,829	**-**	308,148

AMS.I.C (Thermal Displacement Component)

Year	Emission of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)
2011	0	7,345	0	7,345
2012	0	7,345	0	7,345
2013	0	7,345	0	7,345

Year	Emission of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)
2014	0	7,345	0	7,345
2015	0	7,345	0	7,345
2016	0	7,345	0	7,345
2017	0	7,345	0	7,345
Total (tonnes CO_2e)	**0**	51,413	**0**	51,413

AMS.I.D (Electricity Generation Component)

Year	Emission of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)
2011	0	3,221	0	3,221
2012	0	3,221	0	3,221
2013	0	3,221	0	3,221
2014	0	3,221	0	3,221
2015	0	3,221	0	3,221
2016	0	3,221	0	3,221
2017	0	3,221	0	3,221
Total (tonnes CO_2e)	**0**	22,550	**0**	22,550

Overall Emission Reduction (AMS III.H, I.D and I.C)

Year	Emission of project activity emissions (tCO2e)	Estimation of baseline emissions (tCO2e)	Estimation of leakage (tCO2e)	Estimation of overall emission reductions (tCO2e)
2011	12,240	66,828	0	54,587
2012	12,240	66,828	0	54,587
2013	12,240	66,828	0	54,587
2014	12,240	66,828	0	54,587
2015	12,240	66,828	0	54,587
2016	12,240	66,828	0	54,587

2017	12,240	66,828	0	54,587
Total (tonnes CO_2e)	85,681	467,793	**0**	382,109

B.7 Application of a monitoring methodology and description of the monitoring plan:

B.7.1 Data and parameters monitored:

The following data and parameters will be monitored after the implementation of the project. The values provided in this section are the ones used for the ER estimations provided in this PDD.

Data / Parameter:	$Q_{ww,i,y}$
Data unit:	m^3 /month
Description:	Volume of wastewater treated in the project activity
Source of data to be used:	Measured - Volumetric flow meters
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1,134,000 m3 / year (ex-ante estimate)
Description of measurement methods and procedures to be applied:	The data is measured continuously using Volumetric flow meters. The flow meter will be integrated with SCADA (Supervisory Control And Data Acquisition system) to have real time data monitoring and control. The monthly data will be used in the calculation of emission reductions.
QA/QC procedures to be applied:	The meters will be calibrated periodically based on manufacturer's specification from a certified testing agency but at least once every year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$COD_{ww,untreated,y}$
Data unit:	t COD/m3
Description:	COD of wastewater before the wastewater treatment system (UASB) in the project activity.
Source of data to be used:	Measured – Colorimetric analysis.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.01505 t/m3 – based on a measurement campaign as given in Annex 3.
Description of measurement methods and procedures to be applied:	The COD content will be analyzed using a colorimetric method in the on-site laboratory. The results will be logged in the plant operation report on a daily basis. The measurement will be undertaken according to national or international standards. In case COD is measured using representative sampling, samples and measurements shall ensure a 90/10 confidence level.
QA/QC procedures to be applied:	The colorimetric measurement will be in line with the manufacturer's specification. The colorimeter will be calibrated based on standard samples as well by an external agency atleast one every year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$COD_{ww,treated,k,y}$
Data unit:	tCOD/m3
Description:	COD of wastewater after the wastewater treatment system (UASB) in the project activity.
Source of data to be used:	Measured – Colorimetric analysis.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.00075 t/m3 – based on initial assumption of 95% COD reduction in the UASB.
Description of measurement methods and procedures to be applied:	The COD content will be analyzed using a colorimetric method in the on-site laboratory. The results will be logged in the plant operation report on a daily basis. The measurement will be undertaken according to national or international standards. In case COD is measured using representative sampling, samples and measurements shall ensure a 90/10 confidence level.
QA/QC procedures to be applied:	The colorimetric measurement will be in line with the manufacturer's specification. The colorimeter will be calibrated based on standard samples as well by an external agency at least one every year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$S_{final,PJ,y}$
Data unit:	ton
Description:	Amount of dry matter in final sludge generated by the project activity in the year y
Source of data to be used:	Measured – weighbridge
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 – initial assumption
Description of measurement methods and procedures to be applied:	The project proponent does not envisage the generation of any sludge during the crediting period, however in case sludge is generated and removed from the digester; records will be kept on its quantity and disposal method and end use of final sludge. Frequency of measurement cannot be specified ex-ante. The total quantity of sludge will be measured on a wet basis. 100% of sludge will be monitored through continuous or batch measurements. The volume and density or direct weighing may be used to determine the sludge amount on wet basis. The moisture content will be monitored through representative sampling to ensure 90/10 confidence level.
QA/QC procedures to be applied:	The measurement equipment shall be calibrated on regular basis.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$Q_{biogas,gas\ engine,y}$
Data unit:	Nm^3
Description:	Quantity of biogas combusted in gas engine during the year y

Source of data to be used:	Measured – continuous flow meter
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2,895,663 – ex-ante estimate, please refer to calculation spreadsheet.
Description of measurement methods and procedures to be applied:	The biogas shall be monitored using continuous flow meter. The measurement will be taken on an hourly basis. The flow meter will be integrated with SCADA (Supervisory Control And Data Acquisition system) to have real time data monitoring and control. The biogas flow meter displays output as normalised flow of biogas.
QA/QC procedures to be applied:	The gas flow meter will be calibrated at regular intervals based on manufacturer specification from a certified testing agency or institution. However, it will be made sure that calibration is done at least once a year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$Q_{biogas,boiler,y}$
Data unit:	Nm^3
Description:	Quantity of biogas combusted in thermal boiler during the year y
Source of data to be used:	Measured – continuous flow meter
Value of data applied for the purpose of calculating expected emission reductions in section B.5	4,058,104 - ex-ante estimate, please refer to calculation spreadsheet.
Description of measurement methods and procedures to be applied:	The biogas shall be monitored using continuous flow meter. The measurement will be taken on an hourly basis. The flow meter will be integrated with SCADA (Supervisory Control And Data Acquisition system) to have real time data monitoring and control. The biogas flow meter displays output as normalised flow of biogas.
QA/QC procedures to be applied:	The gas flow meter will calibrated at regular intervals based on manufacturer specification from a certified testing agency or institution. However, it will be made sure that calibration is done at least once a year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$Q_{biogas, flare, y}$
Data unit:	Nm^3
Description:	Total quantity of biogas flared during the year y
Source of data to be used:	Measured – continuous flow meter provided at the inlet of flare system.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	229,768.29 Nm3 – due to conservative estimates on electricity generation part.
Description of measurement methods and procedures to be applied:	The biogas shall be monitored using continuous flow meter. The measurement will be taken on an hourly basis. The flow meter will be integrated with SCADA (Supervisory Control And Data Acquisition system) to have real time data monitoring and control. The biogas flow meter displays output as normalised flow of biogas.

QA/QC procedures to be applied:	The gas flow meter will calibrated at regular intervals based on manufacturer specification from a certified testing agency or institution. However, it will be made sure that calibration is done at least once a year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$EG_{BL,y}$
Data unit:	MWh
Description:	Quantity of electricity generated and exported to the grid by the project activity during the year *y*
Source of data to be used:	Electricity invoices and monthly joint meter readings
Value of data applied for the purpose of calculating expected emission reductions in section B.5	6,078 MWh – initial assumption based on 938 kW of electricity exported for 270 days.
Description of measurement methods and procedures to be applied:	The electricity exported will be continuously measured using the energy meters. The readings will be based on monthly joint meter readings and invoices to PEA.
QA/QC procedures to be applied:	The calibration of the export meters is under the control of the PEA.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$EC_{PJ,j,y}$
Data unit:	MWh
Description:	Quantity of electricity consumed by the project electricity consumption source j in year y
Source of data to be used:	Electricity invoices
Value of data applied for the purpose of calculating expected emission reductions in section B.5	729.972 MWh – based on ex-ante assumption of 112.65kW installed capacity, 6480 hours of operation.
Description of measurement methods and procedures to be applied:	The electricity consumption will be based on the electricity imported by the project activity from the grid. This will be continuously measured using the energy meters. The readings will be based on monthly invoices.
QA/QC procedures to be applied:	The calibration of the export meters is under the control of the PEA.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	T_{out}
Data unit:	Deg C
Description:	Temperature of thermic fluid leaving the boiler for heat transfer
Source of data to be used:	Temperature gauge – Boiler logbook
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	Temperature gauge shall be used to monitor the temperature of the thermic fluid continuously. The data will be recorded in the log books on an hourly basis.

QA/QC procedures to be applied:	The temperature gauge shall be calibrated as per manufacturer's specification but at least once every year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	T_{in}
Data unit:	Deg C
Description:	Temperature of thermic fluid entering the boiler after heat transfer
Source of data to be used:	Temperature gauge – Boiler logbook
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	Temperature gauge shall be used to monitor the temperature of fluid going back into boiler. The data shall be monitored continuously and recorded in the log books on an hourly basis.
QA/QC procedures to be applied:	The temperature gauge shall be calibrated as per manufacturer's specification but at least once every year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$Q_{oil, y}$
Data unit:	m^3
Description:	Quantity of the thermic fluid from boiler to the process plant.
Source of data to be used:	The project proponent will install the flow measurement device to monitor the flow of thermic fluid oil.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	The parameter will be measured continuously using flow meter. The data will be recorded hourly and aggregated daily.
QA/QC procedures to be applied:	The flow meter shall be subject to regular calibration as per manufacturer specification or at least once every year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$LHC_{oil,avg}$
Data unit:	cal/g-^oC
Description:	Average liquid head capacity
Source of data to be used:	Data sheet of the thermic fluid (e.g Therminol-55)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	The parameter will calculated annually or per verification period by taking values from the thermic fluid data sheet corresponding to T_{in} and T_{out}.
QA/QC procedures to be applied:	N/A

Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$\rho_{oil,avg}$
Data unit:	Kg/m3
Description:	Average density of thermic fluid
Source of data to be used:	Data sheet of the thermic fluid (e.g Therminol-55)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	The parameter will calculated annually or per verification period by taking values from the thermic fluid data sheet corresponding to T_{in} and T_{out}.
QA/QC procedures to be applied:	N/A
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$FV_{RG,h}$
Data unit:	Nm^3/h
Description:	Volumetric flow rate of the residual gas in dry basis at normal conditions in the hour *h*
Source of data to be used:	Measured by project developer using a flow meter
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	The parameter is measured continuously on dry basis. The values will be averaged every hour. It will be ensured that same basis (dry or wet) is considered for this measurement and the measurement of volumetric fraction of methane when the temperature of residual gas exceeds 60 Deg C.
QA/QC procedures to be applied:	The flow meter will be calibrated as per manufacturer's specifications.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$fv_{CH4,RG,h}$, $w_{CH4,y}$
Data unit:	-(fraction)
Description:	Volumetric fraction of component *methane* in the residual gas in the hour h
Source of data to be used:	Measured by project developer using a continuous gas analyser
Value of data applied for the purpose of calculating expected emission reductions in section B.5	65% - for ex-ante estimation.
Description of measurement methods and procedures to be applied:	The methane percentage shall be measured using continuous gas analyser. The value will be averaged hourly or at a shorter time interval. In case the continuous gas analyser is not available (or functioning), a portable gas analyser shall be used to monitor the methane content. The

	measurement using portable gas analyser will ensure 90/10 confidence/precision level. It will be ensured that same basis (dry or wet) is considered for this measurement and the measurement of volumetric flow rate when the temperature of residual gas exceeds 60 Deg
QA/QC procedures to be applied:	The gas analyser will be periodically calibrated according to manufacturer's specifications/recommendation or once a year. A zero check and a typical value check will be performed by comparison with a standard certified gas.
Any comment:	The data will be stored for the crediting period + 2 years.

Parameter:	T_{flare}
Unit:	°C
Description:	Temperature in the exhaust gas of the flare
Source of data:	Temperature sensor
Value of data:	-
Brief description of measurement methods and procedures to be applied:	The flame temperature will be continuously measured using a Thermocouple. The data will be recorded in the SCADA system but if this data is not available during a monitoring period, the flare efficiency will be assumed to be zero.
QA/QC procedures to be applied (if any):	Thermocouple will be subject to calibration or replacement as per manufacturer's specification.
Any comment:	The data will be stored for the crediting period + 2 years.

Parameter:	Duration of flare temperature (T_{flare}) being more than 500°C
Unit:	minutes/hour
Description:	Duration of flare temperature (T_{flare}) being more than 500°C
Source of data:	SCADA system
Value of data:	-
Brief description of measurement methods and procedures to be applied:	The SCADA system will record duration of flare operation. If this data is not available during a monitoring period, the flare efficiency will be assumed to be zero.
QA/QC procedures to be applied (if any):	Not applicable.
Any comment:	The data will be stored for the crediting period + 2 years.

Parameter:	Other flare operation parameters
Unit:	-
Description:	All the data and parameters that are required to monitor whether the flare operates within the range of operating conditions are already included above in this section of the PDD.
Source of data:	As above
Value of data:	-
Brief description of measurement methods and procedures to be applied:	Not applicable
QA/QC procedures to be applied (if any):	Not applicable.
Any comment:	-

Data / Parameter:	$FC_{k,y}$
Data unit:	m^3/year
Description:	Quantity of fossil fuel type k combusted in the thermal oil boiler
Source of data to be used:	Measured using flow meters
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 – (fuel oil) for ex-ante estimation
Description of measurement methods and procedures to be applied:	The amount of fuel used in the boiler will be monitored continuously using a flow meter. The records will be kept as and when fossil fuel is used in the project activity. Default density value as given in section B.6.2 will be used to convert m^3 in to tonne.
QA/QC procedures to be applied:	The measured value can be cross-checked with the purchase records. The flow meter will be calibrated as per manufacturer's specification or at least once a year.
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$EF_{CO2,k,y}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor of fossil fuel type k combusted in the boiler
Source of data to be used:	National value (if available) or most recent IPCC values
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be applied:	As per the " Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", the following order will be followed: (i) Values provided by fuel supplier in invoices (ii) Regional or national default values (iii) IPCC default values at the upper limit of the uncertainty at a 95% confidence interval as provided in Table 1.4 of Chapter 1 of vol 2 of the 2006 IPCC
QA/QC procedures to be applied:	Any future revision of the IPCC Guidelines will be taken into account
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$NCV_{k,y}$
Data unit:	GJ/tonne
Description:	Net calorific value of fossil fuel type k combusted in the boiler
Source of data to be used:	National value (if available) or most recent IPCC values
Value of data applied for the purpose of calculating expected emission reductions in section B.5	-
Description of measurement methods and procedures to be	As per the " Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion", the following order will be followed:

applied:	(i) Values provided by fuel supplier in invoices (ii) Regional or national default values (iii) IPCC default values at the upper limit of the uncertainity at a 95% confidence interval as provided in Table 1.2 of Chapter 1 of vol 2 of the 2006 IPCC
QA/QC procedures to be applied:	Any future revision of the IPCC Guidelines will be taken into account
Any comment:	The data will be stored for the crediting period + 2 years.

Data / Parameter:	$TDL_{j,y}$
Data unit:	%
Description:	Average technical transmission and distribution losses for providing electricity to the project activity (electricity import)
Source of data to be used:	Annual report published by DEDE and Ministry of Energy, Thailand
Value of data applied for the purpose of calculating expected emission reductions in section B.5	5.9% (based on most recent report published – Electric Power In Thailand - 2009
Description of measurement methods and procedures to be applied:	As per the guidance given in the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption", most recent data available within the host country will be used during monitoring and verification.
QA/QC procedures to be applied:	Not applicable.
Any comment:	The data will be stored for the crediting period + 2 years.

B.7.2 Description of the monitoring plan:

1. Monitoring Management

The required monitoring equipments will be installed and monitoring procedures will be followed as mentioned in section B.7.1. The data will be recorded on a continuous basis or as indicated in section B.7.1 and fed into the log books and the SCADA system. The data will be kept in both soft and hard copy format and proper data backups will be maintained. The calibration of monitoring equipments will be done on regular intervals as per manufacturer's specification or at least once every year. However, calibration of energy meters for the measurement of export/import is under the responsibility of PEA.

All biogas plant staff will be trained by the Papop Co., Ltd., prior to full commissioning of biogas plant. The training records can be checked during future verifications. The figure below outlines the structure of operation and management of the project activity.

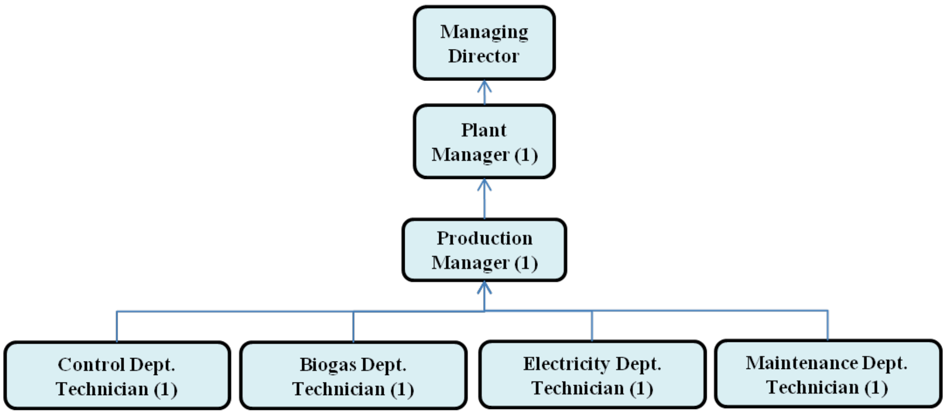

Figure : Maesot Biogas Co., ltd. organization chart

The overall responsibility regarding the proper operation, maintenance and CDM monitoring lies with the Managing Director who will be supported by the technicians who will undertake the actual measurements. Further South Pole[60] will provide necessary support and advice to monitor the data as per the CDM requirement. Both, Papop and South Pole have sufficient experience in monitoring such project type and with their regular follow ups it is not expected that there will be major issues in future.

2. Quality Assurance and Quality Control

The team mentioned above will ensure proper and timely calibration (in accordance with the manufacturer specifications) of systems, data acquisition and storage. The managers will also undertake regular follow ups to make sure the data measured is consistent.

3. Data Storage and Filing

All monitoring data will be stored in the log-books and in electronic format. The monitoring records shall be archived for a period of the crediting period plus 2 years.

4. Emergency preparedness

The project activity is not expected to result in any emergency that can result in substantial emissions.

However, leakages, if any, in the piping or digester shall come to the attention of the plant operator either instantly on the control screen, or at the time of data logging. The team shall take necessary action to stop any such leakage etc. and put plant operation back on track. The project activity has many provisions to guarantee safety and some of these include pressure controller, gas analyser, automatic blowout, flame arrestor and switches. The operation manual for the project activity includes procedures on safety which will make sure that the operators are fully aware of emergency procedures.

5. Uncertainty in data

[60] South Pole Carbon Asset Management Ltd is a 100% subsidiary of South Pole Holding Ltd and is providing CDM related services for the project activity mentioned in this PDD.

Some uncertainties may result due to malfunction of meters, calibration issues and wrong data collection (gaps in manual log sheets, human errors by plant operators). The operator is expected to put best efforts to prevent such errors, however regular internal audits shall rectify any such uncertainty in the monitored data.

6. Implementation Status of the project activity

As of 4th July 2011, the project activity has been fully commissioned. The project activity is expected to operate as per the initial design during the crediting period.

B.8 Date of completion of the application of the baseline and monitoring methodology and the name of the responsible person(s)/entity(ies)

Completion date: 30/12/2009

Patrick Bürgi
South Pole Carbon Asset Management Ltd.[61]
Technoparkstrasse 1
CH-8005 Zurich
Switzerland

SECTION C. Duration of the project activity / crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

25/02/2009 – First payment made to the technology provider

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

15 years

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

C.2.1. Renewable crediting period

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

01/09/2011 or the date of registration whichever is later.

C.2.1.2. Length of the first crediting period:

07 years 00 months

[61] South Pole Carbon Asset Management Ltd is a 100% subsidiary of South Pole Holding Ltd and is providing CDM related services to the project activity mentioned in this PDD.

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

Not Applicable

C.2.2.2. Length:

Not Applicable

SECTION D. Environmental impacts

D.1. If required by the host Party, documentation on the analysis of the environmental impacts of the project activity:

The proposed Project is not required to undertake an Environmental Impact Assessment according to the Thailand regulations (http://www.onep.go.th/eia/). Initial Environmental Evaluation (IEE) has been done as part of the requirement of the Thai DNA[62]. The IEE report must be approved in relation to Thai sustainable development criteria for CDM. This process ensures that a project with a negative impact to the environment is considered in parallel with GHG reductions of the project. The main conclusion of IEE reports are;

- The air pollutants from the thermal and power generation process will be treated before releasing into the atmosphere. The value of air emission after the treatment system is under the Thai industrial regulation standard. Due to the utilization of biogas, no harmful pollutants or smoke/soot will be emitted. The impact on air quality is very low.
- The report evaluated the noise level generated by the project activity is lower than the standard as following.

Parameters	National standard[63]
Lmax	< 115 dB(A)
Leq 24 hr	< 70 dB(A)
Annoyance Noise	< 10 dB(A)

- The quality of effluent after the wastewater treatment system is under the Thai industrial regulation standard. The UASB system enhances COD reduction in the wastewater. The treated wastewater may be used for agricultural purpose and reused in the starch production process.

The preventive and mitigation measures to the environmental impact have been prepared. The IEE report also recommended monitoring measures of pollutants other than the greenhouse gases covered under the

[62] Outline of CDM project approval process. Thailand Greenhouse Gas Management Oranization (Public Organization). Source: http://www.tgo.or.th/english/index.php?option=com_content&task=view&id=60&Itemid=52

[63] Notification of the Ministry of Industry on Specification of Annoyance Noise and Noise Level from the Factory. B.E. 2548 (2005)

Kyoto Protocol (CO, NO_2, PM, etc). All the recommendations from the IEE report will be adopted by the project developer.

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

No negative environmental effects are expected from the implementation of the project as a result of Initial Environmental Examination, which is a requirement of the Thai DNA.

SECTION E. Stakeholders' comments

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

Procedure followed to invite stakeholder comments

Public hearing for local stakeholders:

Invitation procedure

The stakeholder consultation was conducted by the project owner Maesod Biogas Co Ltd. with assistance from South Pole Carbon Asset Management Limited (company responsible for CDM project development).

Stakeholder groups were identified and they were informed through oral and written means about the meeting. The invitation letter was sent by fax to participants located far from the project site, in person to participants without access to a fax and there was also an announcement of the meeting posted at the community hall for people who had not received an invitation letter. This invitation process was done 2 weeks before the meeting date.

The persons or organizations invited were as follows:

Government Sector, State Agency, Independent Entity and Private Organization

- National Science and Technology Development Agency (NSTDA)
- Thailand Environment Institute (TEI)
- Office of Natural Resources and Environmental Policy and Planning
- Ministry of Agriculture and Cooperatives
- Green Leaf Foundation
- International Institute for Energy Conservation (IIEC)
- Thailand Development Research Institute (TDRI)
- The Environmental Engineering Association of Thailand (EEAT)
- Thailand Greenhouse Gas Management Organization (TGO)
- NGOs supporting the GS, which areThe Climate Group, Appropriate Technology Association (ATA), Dhammanart Foundation, Renewable Energy Institute of Thailand (REIT), Greenpeace International, and Mercy Corps and WWF international.
- Department of Environmental Engineering of Chulalongkorn University

- Department of Environmental Engineering of King Mongkut's University of Technology Thonburi (KMUTT)
- Faculty of Environment and Resource Studies of Mahidol University

Local Participants
- Assistant district officer
- Mayor
- Superintendent
- Provincial Electricity Authority
- Headman in surrounding area of the project
- Village headman in surrounding area of the project
- Villager

Place and date of the meeting
The stakeholder consultation was held at a meeting room of Dong Sak Golf Driving Range on August 24, 2009.

Meeting Participants
The meeting was attended by local residents and representatives from the following stakeholder categories:

1. Local residents/farmers
2. Local government representatives
3. Local entrepreneurs
4. Employee

There were 30 participants who accepted the invitation, attended the meeting and returned the questionnaire.

Language
The documentation and meeting were in Thai which is the local language.

Meetings procedure

- Registration (30 min)
- Opening (15 min)
- Introduction by Maesot Biogas Company (15 min)
- Description of the project and environmental impacts (30 min)
- Purpose of CDM, and relation of the project and CDM (30 min)
- Questions and Answers session (10 min)
- Completing questionnaire (20 min)

Meeting documents and protocols
On completion of the various components of the meeting, the following documents were collected and attested by the signatures of the stakeholders that were present at the time:

1. Attendance list with name, address and occupation.

2. Non-technical description of the project.
3. Questionnaire.

E.2. Summary of the comments received:

The overall response to the project from all invited stakeholders was encouraging and positive. There were two questions during the meeting; one of these questions was related to concerns on the environmental impact of odor from the implementation of the project, the other question was related to employment. Both questions were clarified during the meeting. The greatest benefit achieved by the project was agreed to be the positive effect on the environment. Stakeholders acknowledge that the improvement of wastewater treatment technology will reduce odors released to the surrounding area. This project is viewed as a positive environmental plan that is important for local water resources and the community's quality of life.

To sum up the sustainability of the project, the various benefits (as reported by local stakeholders) are listed below.

1. The installed technology contributes to better water quality and reduced odours.
2. Use of biogas represents a sustainable way for generating energy.
3. While the system operates within strict environmental standards there will be no negative impacts to the environment due to the project.
4. The project is well designed and not producing additional pollution.
5. The project will create new jobs at the plant.

No adverse comments have been received during the stakeholder consultation process.

Summary of comments received during forum:

- *Will the project cause air pollution?*

No the project will not cause air pollution as the wastewater treatment system UASB is a closed system and does not cause odour in the surrounding area. Further, the biogas system is equipped with bio-scrubber which will reduce the quantity of sulphur in biogas and therefore reducing SOx emissions.

- *How will the company employ the staff?*

The company will give preference to qualified local people.

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

As no major concerns were raised during the entire stakeholder consultation process, it was neither necessary to make any changes to the project design nor to incorporate any additional measures to limit or avoid negative environmental impacts.

It is evident from the stakeholder consultation process that the project is perceived as a positive example for the tapioca starch factories in Thailand and that it contributes to sustainable development of the region.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

There is no public funding in the project activity.

Annex 3

BASELINE INFORMATION

COD campaign data

A 10 day COD campaign was conducted in the starch factory Chaophyapeuchrai 2999 (Kamphaengphet) Co., Ltd. The samples were taken in the wastewater treatment system consisting of open anaerobic lagoons. The results from the campaign are as follows:

Sampling date	COD_{in} (mg/l)	COD_{out} (mg/l)	$\%COD_{removal}$
04/02/2010	15711.00	156.00	99.01%
05/02/2010	15195.00	144.00	99.05%
06/02/2010	15468.00	137.00	99.11%
07/02/2010	15033.00	118.00	99.22%
08/02/2010	17930.00	138.00	99.23%
09/02/2010	14540.00	152.00	98.95%
10/02/2010	14606.00	131.00	99.10%
11/02/2010	15157.00	137.00	99.10%
12/02/2010	14627.00	139.00	99.05%
13/02/2010	14509.00	127.00	99.12%
14/02/2010	14240.00	127.00	99.11%
15/02/2010	14369.00	142.00	99.01%
16/02/2010	15023.00	175.00	98.84%
17/02/2010	14336.00	133.00	99.07%
Average	**15053.14**	**139.71**	**99.07%**
Uncertainity factor			0.89
Removal efficiency			88.17%

As shown above, the COD removal efficiency is multiplied by an uncertainty factor of 0.89 as per the requirement in the methodology. The above measurement was conducted by ALS Laboratory Group (Thailand) Co. Ltd. The samples were taken in 250 ml plastic bottle with Sulfuric acid as preservative. The testing was based on APHA 2005, 5220 D method.

Calculation of the grid emission factor of Thailand

The study of the estimation of grid emission baseline is carried out in accordance with the tool **"Tool to calculate the emission factor for an electricity system**", version 02.2.0, approved by the CDM Executive Board at EB61.

The data employed in this study was based on the latest data available at the time of PDD submission for validation to the DOE."[64].

The value applied is **0.530 tCO_2e/MWh**.

The details of the grid emission factor calculation are shown below.

The "***Tool to calculate the emission factor for an electricity system"*** states procedures to determine the following parameters to estimate baseline grid emission factor:

Parameter	SI Unit	Description
$EF_{grid,CM,y}$	tCO_2/MWh	Combined margin CO_2 emission factor for the project electricity system in year *y*
$EF_{grid,BM,y}$	tCO_2/MWh	Build margin CO_2 emission factor for the project electricity system in year *y*
$EF_{grid,OM,y}$	tCO_2/MWh	Operating margin CO_2 emission factor for the project electricity system in year *y*

As per the "***Tool to calculate the emission factor for an electricity system"*** project participants shall apply the following seven steps:

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

[64] "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy http://www.dede.go.th/dede/images/stories/stat_dede/all2008.rar *(PDF file submitted to the DOE)*

Step 1: Identifying the relevant electric power system

The tool defines the *project electricity system* as the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity and that can be dispatched without significant transmission constraints.

The national grid of Thailand is identified as the project electricity system. Electric power transmitted by the national grid includes electricity generated annually by the Electricity Generating Authority of Thailand (EGAT), Independent Power Producers (IPPs), Small Power Producers (SPPs), Very Small Power Producers (VSPPs) and imported electricity from neighbouring countries.

Electricity transfers from connected electricity systems to the project electricity system are defined as electricity imports and electricity transfers to connected electricity system are defined as electricity exports.

For the purpose of determining the operating margin emission factor the CO_2 emission factor of net electricity imports is taken as 0 tCO_2 per MWh.

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

Project participants chose "**Option I**: Only grid power plants are included in the calculation", to calculate the operating margin and build margin emission factor.

This option corresponds to the procedure contained in earlier versions of the tool.

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

The calculation of the Operating Margin, $EF_{grid,OM,y}$, is based on one of the following methods according to the 'Tool to calculate the emission factor for an electricity system':

(a) Simple OM,
(b) Simple Adjusted OM,
(c) Dispatch Data Analysis OM, or
(d) Average OM.

For this proposed project activity, (a) the Simple OM is applied.

According to the 'Tool to calculate the emission factor for an electricity system', version 02.2.0, the simple OM method can only be used if the low –cost/ must-run resources constitute less than 50% of total grid generation in 1) average of the 5 most recent years, or 2) based on long-term averages for hydroelectricity production.

Low –cost/ must-run resources are defined as power plants with low marginal generation costs or power plants that are dispatched independently of the daily or seasonal load of the grid. They typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation.

EGAT is in charge of the national electricity grid for sufficient supply in Thailand. In addition to the power plants owned by EGAT, there are three types of private power companies: Independent Power Producers (IPPs), Small Power Producers (SPPs), Very Small Power Producers (VSPPs). Some of SPP and VSPP power plants use both of renewable and conventional energy. Therefore, the calculation of Low –cost/ must-run in this study includes also electricity generated from SPP and VSPP power plants to be conservative.

Based on the data from "Electricity Power in Thailand 2008", the average Low –cost/ must-run of the five most recent years is determined to be 15.32% as shown in Table 1.

Consequently, the *Simple OM* is deployed for calculation of the OM emission factor in this study.

Table 1. National grid generation in Thailand, 2004-2008

Year	**Total**	**Hydro**	**Other**	**SPP&VSPP**	**Total LCMR**	
	GWh	GWh	GWh	GWh	GWh	%
2004	125,726	6,040	2	13,513	19,555	15.55%
2005	132,195	5,798	2	13,700	19,500	14.75%
2006	138,732	8,125	3	13,721	21,849	15.75%
2007	143,364	8,114	3	14,545	22,662	15.81%
2008	147,388	7,113	5	14,607	21,725	14.74%
Average over last five years						**15.32%**

Source: "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy

Besides, for the simple OM, the simple adjusted OM and the average OM, the emission factor can be calculated using one of the two data vintages mentioned in the tool. The *ex ante* option is chosen:

Ex-ante option: The emission factor is determined once at validation stage, thus no monitoring and recalculation of emission factor during the crediting period is required. For grid power plants, a 3-year generation-weighted average, based on the most recent data available at the time of submission of the CDM-PDD to the DOE for validation.

The data vintage shall not be changed during the crediting period.

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

The simple OM emission factor is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation (tCO_2/MWh) of all generating power plants serving the system, not including low-cost / must-run power plants / units.

Since the data of fuel consumption and electricity generation for each power unit is not available, **option B** of the tool is used. Moreover, only nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known and off-grid power plants are not included in the calculation.

Therefore, the simple OM emission factor can be calculated based on the total net electricity generation of all power plants serving the system and the fuel types and total fuel consumption of the project electricity system, as follows:

$$EF_{grid,OM,simple,y} = \frac{\sum_i (FC_{i,y} \times NCV_{i,y} \times EF_{CO2,i,y})}{EG_y}$$

Where:

$EF_{grid,OM,simple,y}$ =Simple operating margin CO_2 emission factor in year y (t CO_2/MWh)

$FC_{i,y}$ = Amount of fossil fuel type *i* consumed in the project electricity system in year *y*, (mass or volume unit)

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = CO_2 emission factor of fossil fuel type *i* in year *y* (tCO_2/GJ)

EG_y = Net electricity generated and delivered to the grid by all power sources serving the system, not including low-cost/must-run power plants/units in year *y* (MWh)

y = The relevant year as per the data vintage chosen in step 3

Option B can be used since the necessary data for Option A is not available; nuclear and renewable power generation are considered as low-cost/must-run power sources and the quantity of electricity supplied to the grid by these sources is known; and off-grid power plants are not included in the calculation.

For this approach to calculate the operating margin, electricity imports to the grid are included.

<u>Data used and calculations</u>

Table 2. Electricity generation (including imports), EG_y

Year	Electricity generation (GWh)						
	Fuel Oil*	Diesel Oil*	Coal & Lignite*	Natural Gas*	SPP & VSPP**	Import***	Total
2006	8,350	143	22,051	86,339	13,721	5,159	135,763
2007	3,646	174	28,716	88,166	14,545	4,491	139,738
2008	1,454	180	29,480	94,549	14,607	2,785	143,055

* Table 17, Page 21

**Table 16, Page 20

***Table 22, Page 25

#Including geothermal, solar cell and wind turbine, etc.

Ref: "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy

http://www.dede.go.th/dede/images/stories/stat_dede/all2008.rar *(PDF file submitted to the DOE)*

Table 3: Fuel consumption (2006-2008) (fossil fuel based power plant) $FC_{i,y}$

Year	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas
	Million litres	Million litres	Thousand tonnes	(MMscf)
2006	2,022	40	16,250	764,215
2007	936	23	19,650	783,137

2008	350	44	20,465	812,620

Ref : Table 19 Fuel Consumption for Electric generation to National Grid
"Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy *(PDF file submitted to the DOE)*

Table 4: Fuel consumption (2006-2008) (SPP and VSPP) $FC_{i,y}$

Year	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas
	Million litres	Million litres	Thousand tonnes	(MMscf)
2006*	8.1745	0.44	915.93	92,888
2007**	6.9750	1.25	898.83	94,725
2008***	7.5479	1.45	969.82	94,707

Ref:

* Table 20 Fuel Consumption for Co-genration selling to National Grid
http://www.dede.go.th/dede/images/stories/stat_dede/all2006.rar *(PDF file submitted to the DOE)*

** Table 20 Fuel Consumption for Co-genration selling to National Grid

http://www.dede.go.th/dede/images/stories/stat_dede/all2007.rar *(PDF file submitted to the DOE)*

***Table 20 Fuel Consumption for Co-genration selling to National Grid

http://www.dede.go.th/dede/images/stories/stat_dede/all2008.rar *(PDF file submitted to the DOE)*

Table 5: Total Fuel consumption (2006-2008) $FC_{i,y}$ (sum of Table 3 + Table 4)

Year	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas
	litres	litres	tonnes	(MMscf)
2006	2,030,174,530	40,436,418	17,165,933	857,103
2007	942,975,007	24,248,725	20,548,833	877,862
2008	357,547,882	45,449,715	21,434,819	907,327

Table 6: Parameters

Parameters	Fuel Oil	Diesel Oil	Coal & Lignite	Natural Gas	Units
NCV*	39.77	36.42	10.47	1.02	
Units (NCV)	MJ/litre	MJ/litre	MJ/kg	MJ/scf	
$EF_{CO2,i}$ (kg/TJ)**	75,500	72,600	89,500	54,300	tCO2/TJ

http://www.dede.go.th/dede/images/stories/stat_dede/all2008.rar *(PDF file submitted to the DOE)*

* Oil and Thailand 2008, page 42 (conservative values of the NVC of coal and natural gas are used)

http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_1_Ch1_Introduction.pdf
** Lower value in 95% confidential interval of Table 1.4 (Default CO2 emission factors for combustion), Volume 2, Chapter 1, IPCC Guidelines 2006

Conservative value of EF for coal is used (sub-bituminous coal)

Table 7: CO2 Emission (tCO_2)

Year	Fci,y*NCVi,y*EFCO2,i,y			
	Fuel Oil*	**Diesel Oil***	**Coal & Lignite***	**Natural Gas***

2006	6,095,873	106,918	16,085,595	47,471,507
2007	2,831,410	64,116	19,255,592	48,621,265
2008	1,073,586	120,173	20,085,819	50,253,213

Table 8: Simple OM emission factor ($EF_{grid,OM,simple,y}$)

Year	EG,y	FCi,y*NCVi,y*EFCo2,i,y	$EF_{grid,OMsimple,y}$
	GWh	(tCO2)	
2006	135,763	69,759,892	0.514
2007	139,738	70,772,383	0.506
2008	143,055	71,532,791	0.500
			0.507

From the table, $EF_{grid,OM,,,y}$ = **0.507 tCO_2/MWh**

Step 5: Identifying the group of power units to be included in the build margin

In term of vintage of data, **Option 1**: the build margin emission factor *(ex ante)* based on the most recent information available on units already built at the time of CDM-PDD submission to the DOE for validation is chosen, hence, monitoring the emission factor is not required during the crediting period. For the second crediting period, the build margin emission factor should be updated based on the most recent information available on units already built at the time of submission of the request for renewal of the crediting period to the DOE. For the third crediting period, the build margin emission factor calculated for the second crediting period should be used. This option does not require monitoring the emission factor during the crediting period.
According to the 'Tool to calculate the emission factor for an electricity system', version 02.1.2, the sample group of power units *m* used to calculate the build margin should be determined as follows:

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

The following table shows the list of most recently built power units ($SET_{5-units}$ & $AEG_{SET-5-units}$) as per step (a) above. This set of power plants also constitutes 21.9% of the total generation and therefore the same set is selected as SET_{sample}. All these five power plants are not registered as CDM project activity and did not supply electricity to the grid more than 10 years ago.

Table 9. Group of power units to be included in the Build Margin

Plant name	Plant Capacity*	Generation (2008) *	Efficiency**	Energy	Emissions	Type of Fuel*	COD (a)
(Sample group m)	(MW)	(GWh)	(Btu/kWh)	(TJ)	($tCO2$)		COD
EPEC	350	2670	6811	19,184.47	1,041,716.47	Natural Gas	March 2003
BLCP	1346.6	10801	9100	103,689.06	9,280,170.48	Coal	Unit 1 : August 2006 Unit 2: November 2006
GPG	1468	9195	6950	67,416.17	3,660,698.22	Natural Gas	Unit 1 : May 2007 Unit 2: March 2008
RGCO POWER	1400	5812	7051	43,231.86	2,347,489.78	Natural Gas	Unit 1 : May 2008 Unit 2: June 2008
Chana	710	3754	7082	28,046.44	2,510,156.43	Natural Gas	July 2008 (EGAT report)

Source: Electric Power in Thailand 2008 Report, DEDE, Table 8, page 10 and Table 18 page 22 and EPPO website

The Build Margin emission factor is calculated as the generation-weighted average emission factor of all power units m during the most recent year y for which power generation, as follows:

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

Where:

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

The CO_2 emission factor of each power plant unit m ($EF_{EL,m,y}$) should be determined as per the simple OM.

Option A2 is used to calculate it, as there is data on electricity generation, fuel types and the efficiency of the group of power unit to be included in the build margin:

$$EF_{EL,m,y} = \frac{EF_{CO2,m,i,y} \cdot 3.6}{\eta_{m,y}}$$

Where:

$EF_{EL,m,y}$ = CO2 emission factor of power unit *m* in year *y* (tCO_2/MWh)

$EF_{CO2,,m,i,y}$ = Average CO2 emission factor of fossil fuel type *i* in power unit *m* in year *y* (tCO_2/GJ)

$\eta_{m,y}$ = Average net energy conversion efficiency of power unit *m* in year *y* (ration)

m = All power units serving the grid in year *y* except low-cost/must-run power units

y = The relevant year as per the data vintage chosen in Step 3

Table 10: Build Margin emission factor ($EF_{grid,BM,y}$)

Plant name (Sample group m)	Plant Capacity (MW)	Generation (2008) (GWh)	Efficiency (Btu/kWh)	Efficiency %	$EF_{EL,m}$ (tCO2/MWh)	Emissions (tCO2)
EPEC	350.0	2,670.00	6,811	50.10%	0.39	1,041,716
BLCP	1,346.6	10,801.00	9,100	37.50%	0.86	9,280,170
GPG	1,468.0	9,195.00	6,950	49.10%	0.40	3,660,698
RGCO POWER	1,400.0	5,812.00	7,051	48.40%	0.40	2,347,490
Chana	710.0	3,754.00	7,082	48.19%	0.41	1,522,922
Generation of group m is part of total grid generation (GWh)			32,232			
Total grid generation (GWh)			147,388			
Total CO2 emission (tCO2)			17,852,997			
Build margin emission factor (EFgrid, BM,y)			**0.554**			

Ref: "Electric Power in Thailand 2008" Department of Alternative Energy Development and Efficiency (DEDE), Ministry of Energy

http://www.dede.go.th/dede/images/stories/stat_dede/all2008.rar *(PDF file submitted to the DOE)*

From the table, $EF_{grid,BM,,,y}$ = **0.554 tCO_2/MWh**

Step 6: Calculating the combined margin emission factor

The combined margin emissions factor is calculated as per the option (a) weighted average CM as follows:

$$EF_{grid,CM,y} = EF_{gird,OM,Y} * w_{OM} + EF_{grid,BM,Y} * w_{BM}$$

Where:

$EF_{BM,Y}$ = Build margin CO_2 emission factor in year *y* (tCO2/MWh)
$EF_{OM,Y}$ = operation margin CO_2 emission factor in year *y* (tCO2/MWh)
w_{OM} = Weight of operating margin emission factor (%)
w_{BM} = Weight of build margin emission factor (%)

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

- Wind and solar power generation project activities: w_{OM} = 0.75 and w_{BM} = 0.25 (owing to their intermittent and non-dispatchable nature) for the first crediting period and for subsequent crediting periods.
- All other project: w_{OM} = 0.5 and w_{BM} = 0.5 for the first crediting period, and w_{OM} = 0.25 and w_{BM} = 0.75 for the second and third crediting period, unless otherwise specified in the approved methodology which refer to this tool.

For this project activity, which is not a wind or solar power generation project activity, the following weights are chosen: $w_{OM} = 0.5$ and $w_{BM} = 0.5$.

Table 11. Calculation of the Combined Margin factor

		$EF_{grid,CM,y}$
Operating Margin EF	tCO2/MWh	0.507
Build Margin EF	tCO2/MWh	0.554
Weight age for OM (W_{OM})	%	0.500
Weight age for BM (W_{BM})	%	0.500
Combined Margin EF ($EF_{CM,y}$)	tCO2/MWh	**0.530**

Therefore, the baseline emission factor **$EF_{grid,CM,y}$ = 0.530 tCO_2/MWh.**

Annex 4

MONITORING INFORMATION

Please refer to details in section B.7.1 and B.7.2.
