PROJECT CONCEPT NOTE

CARBON OFFSET UNIT (CoU) PROJECT

Title: Renewable Projects at Belagavi, Karnataka

Version 1.0

Date 26/09/2022

First CoU Issuance Period: 9 years, 8 months

Date: 18/01/2013 to 18/09/2022

Project Concept Note (PCN)
CARBON OFFSET UNIT (CoU) PROJECT

BASIC INFORMATION	
Title of the project activity	Renewable Projects at Belagavi, Karnataka
Scale of the project activity	Small Scale
Completion date of the PCN	26/09/2022
Project participants	First Climate India Private Limited (AGGREGATOR) Millennium Starch India Private Limited (DEVELOPER)
Host Party	India
Applied methodologies and standardized baselines	**AMS-I.C.**: Thermal energy production with or without electricity **AMS-III.H**: Methane Recovery in Wastewater Treatment **AMS-I.F**: Renewable electricity generation for captive use and mini-grid
Sectoral scopes	01 Energy industries (Renewable/Non-Renewable Sources) 13 Waste Handling and Disposal
Estimated amount of total GHG emission reductions	19,403 CoUs/annum for 1st 9 Years 8 Months, i.e. 1, 87,559 CoUs. Henceforth, average ex-ante estimate is 33,826 CoUs (33,826 tCO_2 eq/annum)

SECTION A. Description of project activity

A.1. Purpose and general description of Carbon offset Unit (CoU) project activity >>

The project **"Renewable Projects at Belagavi, Karnataka"** is located in SPL Plot No-01, Sy No-1078 & 1079, KSSIDC Industrial Estate Satti Road Athani, Post and TQ-Athani, Dist-Belagavi, State- Karnataka-591304, India.

The details of the registered project are as follows:

Purpose of the project activity:

The proposed project activity is promoted by Millennium Starch India Private Limited (henceforth referred to as MSI) in their industrial premises.

The project activity involves the installation of the following units:

Project I: 8 TPH biomass fired boiler with a 550 kW back pressure turbine commissioned in the year 2013 is set to cater the electricity and steam demand of MSI

Project II: 4800 m^3/day biogas generation unit with a gas engine of capacity 800 kW, commissioned in the year 2020 is set to extract and capture methane-enriched biogas generated from the treatment of effluent (wastewater) and to use the captured biogas for the generation of clean power.

This project activity II is based on two complementary activities for the generation of electricity as follows:

• Firstly, anaerobic treatment of effluent (wastewater) in closed digester system and collection of methane-enriched biogas from the digester. This reduces methane emissions into the atmosphere that would have otherwise been emitted from the existing open lagoons.
• Secondly, combustion of captured methane enriched biogas in a gas engine to generate renewable electricity, thus converting its methane content into carbon dioxide thereby reducing its greenhouse effect.

All of the generated electricity and steam will be consumed entirely by the facilities at the MSI site.

The project activity I is expected to generate about 29,640 MT of process steam and 3.26 GWh of electricity per annum. In absence of this project, an equivalent amount of energy and steam would have been sourced from more carbon intensive sources i.e., Coal. The annual average estimated emission reductions are 16,111 tCO2/annum.

The project activity II is expected to generate an average of 4,736.8 MWh of clean energy annually. In absence of the project activity methane would have been emitted from the anaerobic treatment of the effluent in open lagoon and equivalent amount of electricity would have been sourced from grid. The annual average estimated emission reductions from both methane capture and generation of electricity from the captured biogas are 17,715 tCO_2.

Hence, the project activity would reduce total 33,826 t-CO2e/annum greenhouse gas emissions (GHG) by avoiding methane emission from anaerobic treatment of effluent and fossil fuel combustion for steam and power generation.

A.2 Do no harm or Impact test of the project activity>>

There are social, environmental, economic and technological benefits which contribute to sustainable development.

- **Social benefits:**
- The project activity would help to alleviate poverty in the area as it creates employment opportunities for the local people during the construction, operation and maintenance phases and also through handling of biomass material to the project plant.

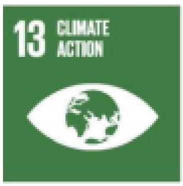
- **Environmental benefits:**
- The project activity will help in conservation of fast depleting natural resources like fossil fuels, thereby contributing to the economic well-being of country as a whole.
- The project activity collects and combusts methane enriched biogas for electricity generation, thus converting CH_4 to CO_2, reducing its greenhouse gas effect. It also uses biomass for power generation thus displacing a certain amount of fossil fuels used for equivalent amount of electricity generation.

- **Economic benefits:**
- In this project activity, the electrical and thermal energy is generated by the renewable fuels which replaces carbon emission intensive fossil fuels. As renewable fuel/biomass is considered to be GHG neutral fuel, combustion of biomass in this project activity does not result in net increase of GHG emissions. Besides the GHG emission reduction, the project activity also reduces emission of SOx, NOx, etc. associated with the combustion of fossil fuels.
- As the plant has its own biogas generation unit, hence the carbon emission due to transportation of fuel get reduced.

PP would like to highlight some of the critical Sustainable Development Goal (SDGs) which are essentially associated with the project activity.

SDG 15

"Protect, restore and promote sustainable use of terrestrial ecosystems, sustainably manage and reverse land degradation and halt biodiversity loss" Since the project essentially manages various types of wastes and also helps improving soil carbon in the agricultural fields, hence it has significant positive impact on 'Life on Land'.



SDG 13

"Take urgent action to combat climate change and its impacts". The project will reduce GHG emissions from different wastes through biogas digesters with methane capture and destruction. Additionally, renewable power generation for captive power demand and application of residual wastes (i.e.by-products) as bio-manure into the soil application further contributes to climate change mitigation actions.

SDG 9

“Build resilient infrastructure, promote inclusive and sustainable industrialization and foster innovation” The project involves development of a new infrastructure facility in the form of bio-refinery and also will promote inclusiveness with the waste suppliers, farmers who will use the bio-manure etc. Additionally, CBG and its application will ensure sustainable industrialization and innovation into the sector.

SDG 5

“Achieve gender equality and empower all women and girls”. The project intends to create job opportunities for female which will bring gender equality; also at the plant level and at the organization level, the company practices zero tolerance policy to various aspects of women rights, safety, security, discrimination etc.

SDG 3

“Target 3.9: Substantially reduce the number of deaths and illnesses from hazardous chemicals and air, water and soil pollution and contamination”.

The project will essentially reduce impacts on the quality of the water and soil by means of recovery of animal manure and agri-wastes. Also the displacement of fossil fuel (diesel) by means of CBG helps improving the air quality and avoidance of hazardous chemicals etc. Thus, the project has direct positive impact on human health in long run.

SDG 1

“Target 1.1: Strengthen financial conditions of local people to reduce risk of low income vulnerability against the poverty line, according to national definitions”.

The project creates both direct and indirect jobs for local population in the project region which will strengthen the financial conditions of the local stakeholders.

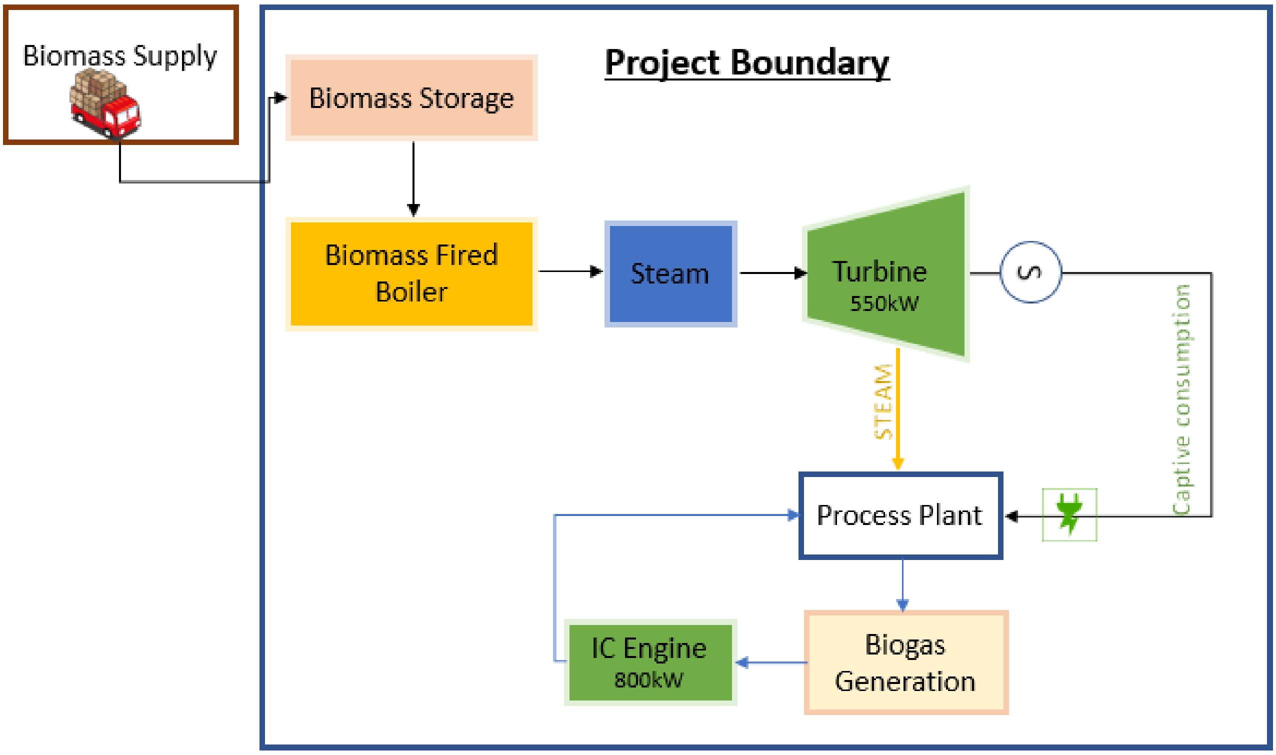
A.3. Location of project activity >>

Country: India
District: Belagavi
City: Athani
State: Karnataka
Code: 591304
The project site is well connected by district and village roads to the nearest town. The geographic coordinates of the project location are:
Latitude: 16^0 41’01.99”
Longitude: 75^0 04’19.87”

Google map showing location of the project activity

A.4. Technologies/measures >>

Process Flow:



The manufacturing process at MSI demands both electrical and thermal energy to run the process and generates high COD effluent as a waste. To manage the wastewater, plant has installed anaerobic wastewater treatment system with biogas recovery. Generated biogas from the wastewater is used for electricity generation through gas engine. To meet the process heat and electricity demand plant has also installed one biomass-based co-generation system. Detail of the systems is as below:

Project Activity I includes a biomass fired co-generation system at its facility.

- The plant has put up an 8 TPH biomass fired boiler which can generate superheated steam at a pressure of 45 kg/cm2 and a temperature of 420 ^{O}C.
- The installed boiler is a multi-fuel boiler.
- Superheated steam directly enters the back pressure turbine of capacity 0.55 MW.
- After the turbine, steam is extracted for process use at a pressure of 38 kg/cm2 and a temperature of 380 ^{O}C.

To operate the plant, proponent could have use coal as a fuel, which is very common across the industry sector. Bagasse is considered as renewable biomass. Owing to some operational barriers, plant has decided to operate the co-gen system with biomass to reduce the carbon emission caused by fossil fuels.

As the project is a co-gen system, conventional Rankin cycle is considered. Equipment required for the project are as follows:

- Boiler
- Back pressure turbine
- Alternator
- Boiler and Turbine Auxiliaries
- Cooling water system
- Air pollution controlling system

- BOP

Technical details of boiler and turbine is tabulated below:

Boiler:

Parameter	Unit	Details
Type of boiler	-	FBC Boiler
Boiler rated capacity	TPH	8
Steam Pressure	kg/cm2	45
Steam Temperature	Deg. C	440
Feed water Temperature	Deg. C	98
Fuel Type	-	Bagasse

Turbine:

Parameter	Unit	Details
Type of turbine	-	Back pressure
Inlet steam pressure	kg/cm2	45
Inlet steam temperature	Deg. C	440
Inlet steam quantity	TPH	8
Back pressure	kg/cm2	5
Back pressure steam quantity	TPH	5

Alternator:

Parameter	Unit	Details
Type	-	4 pole
Rated Capacity	kW	550
Rated power factor	-	0.8
Voltage	V	415
Frequency	Hz	50

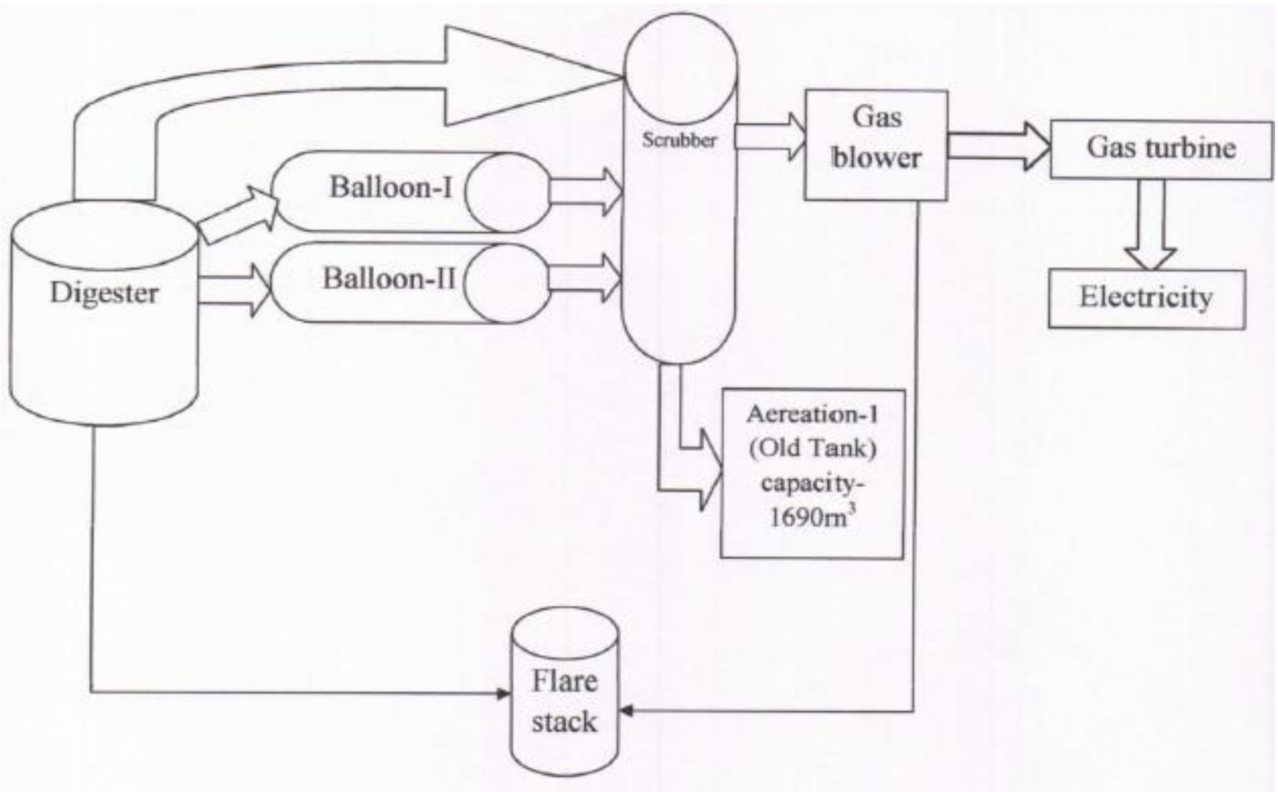
Project activity II employs the following technologies:

- An anaerobic lagoon digester (ALD) which comprises a uniquely designed lagoon process with a wastewater receiving system, a reactor with thick HDPE cover, wastewater recirculation systems,
- Biogas collection/distribution equipment,
- Biogas processing/cleaning equipment,
- Security flare
- Biogas power plant facility.

The ALD will contain the organic rich effluent water in an anaerobic lagoon to optimize the contact with anaerobic bacteria to convert the organic matter into biogas. The system processes the biogas, which involves a scrubber and a gas delivery unit (GDU) to remove hydrogen sulphide, moisture content and adjust the gas pressure before transport to the gas engines. The capacity of the digester is 9600 m3/day.

The biogas fired generators are gas engine with a re-packaged gas train for running on biogas coupled with a generator-set as required for delivery to the plant. The capacity of the power plant is 800 kW, comprising 1 x TCG3016 V16(800Kwe) MWM Bio gas Genset(BGG). The average lifetime of the gensets based on manufacturers' specifications and industry standards is 15 to 20 years.

The following diagram shows the process:



A.5. Parties and project participants >>

Party (Host)	Participants
India	**First Climate (India) Pvt. Limited (AGGREGATOR)** Contact person: Partha P Chaudhuri Mobile: +91 9831012824 Address: 903 ERGO Tower, Plot No. A1-4, Block EP & GP, Sector V, Salt Lake, Kolkata 700 091 **Millennium Starch India Pvt Ltd. (DEVELOPER)** Address: SPL Plot No-01,Sy No-1078 & 1079,KSSIDC Industrial Estate Satti Road Athani, Post and TQ-Athani, Dist-Belagavi, State-Karnataka-591304

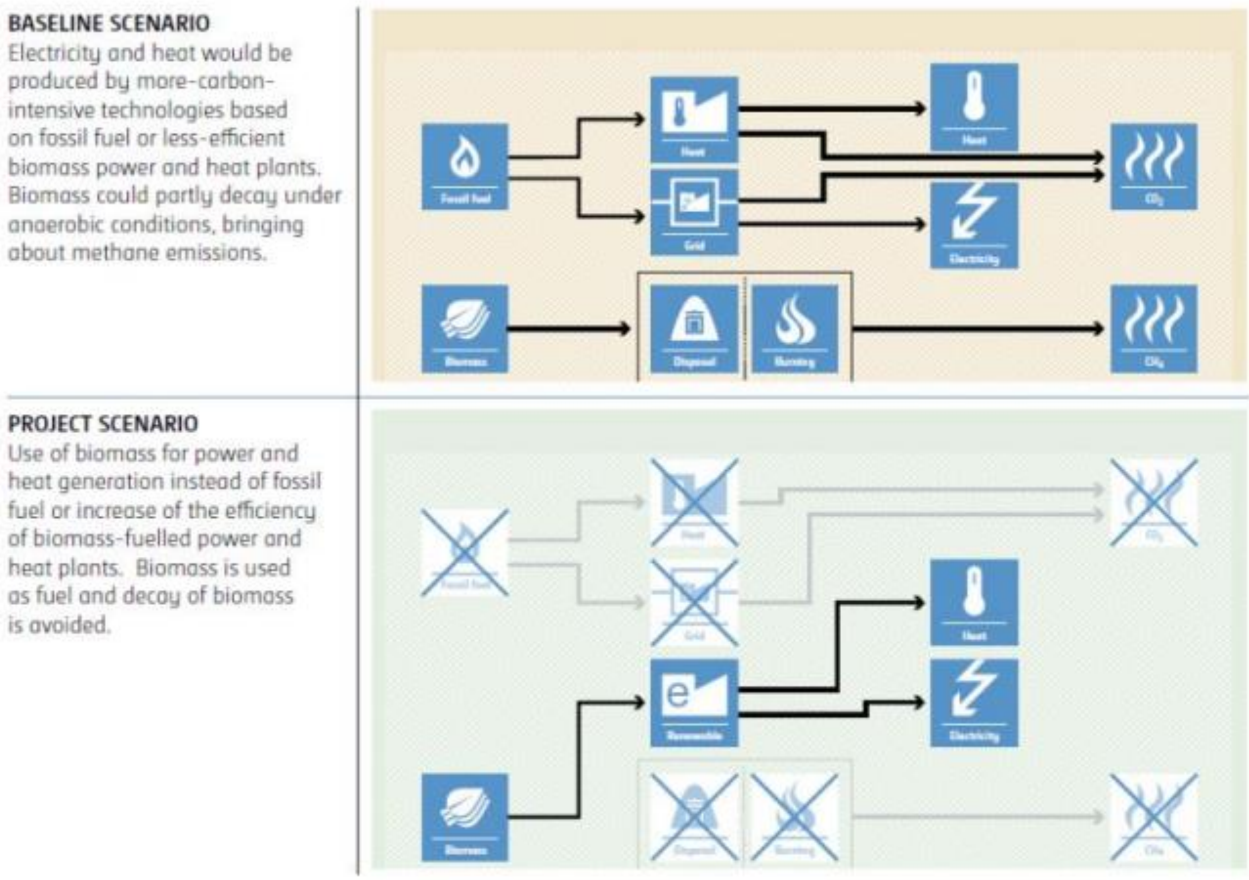
A.6. Baseline Emissions>>

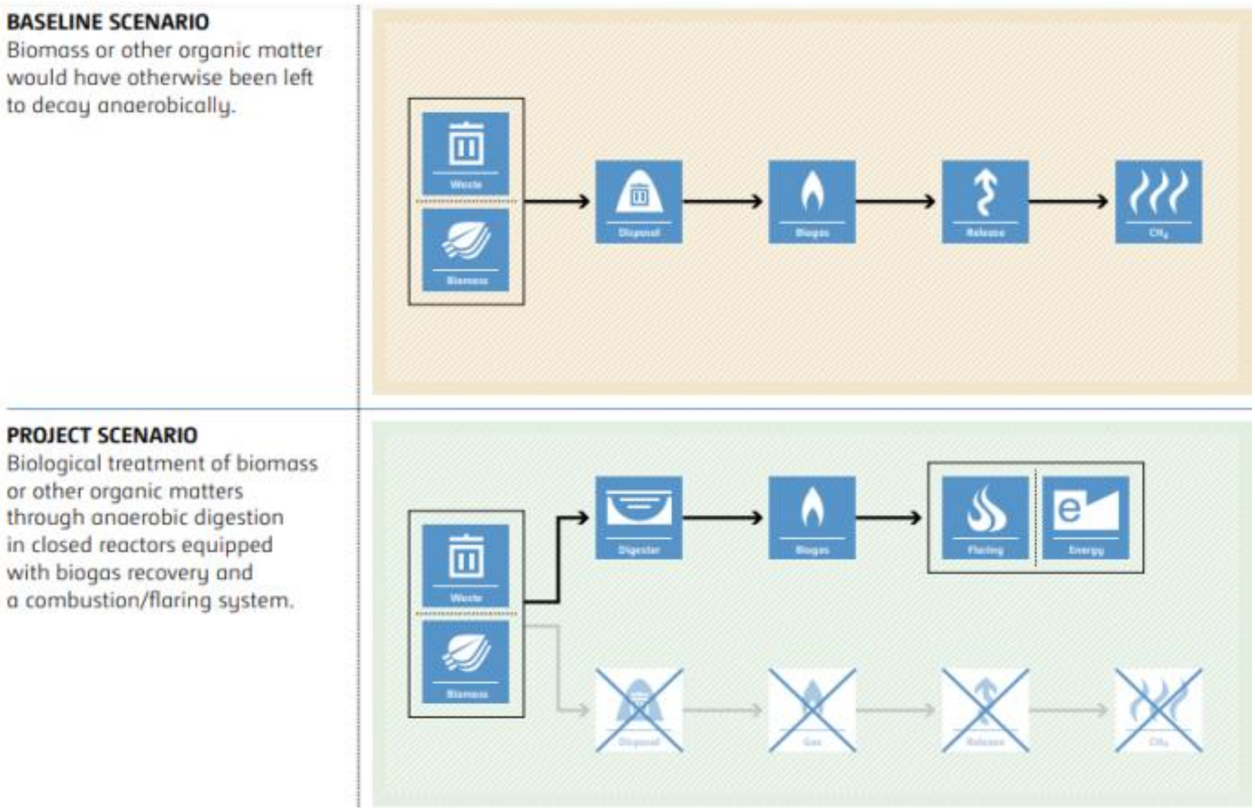
The baseline scenario identified at the PCN stage of the project activity are:

According to AMS-I.C, the baseline scenario identified at the PCN stage of the project activity is a coal based co generation system.

According to AMS-III.H version 19.0, the baseline scenario identified at the PCN stage of the project activity is anaerobic wastewater treatment system without biogas recovery, resulting in free release of methane into the atmosphere.

According to AMS-I.F, the project activity includes electricity generation from the renewable power plant for the captive user. And, hence the renewable power plant can be considered as the installation of new renewable power plant that supply the electricity for captive use, which displace the grid electricity consumption. Hence, the applicable baseline, as per the approved methodology AMS-I.F, the baseline of the project activity is grid electricity which would have otherwise been consumed in absence of the project activity.





A.7. Debundling>>

This **Renewable Projects at Belagavi, Karnataka** project is not a debundled component of a larger project activity.

SECTION B. Application of methodologies and standardized baselines

B.1. References to methodologies and standardized baselines >>

SECTORAL SCOPE –
01 Energy industries (Renewable/Non-renewable sources)
13 Waste handling and disposal

TYPE I - Renewable Energy Projects
III: Other Project Activities

CATEGORY-
AMS-I.C.: Thermal energy production with or without electricity
AMS-III.H: Methane Recovery in Wastewater Treatment
AMS-I.F: Renewable electricity generation for captive use and mini-grid

B.2. Applicability of methodologies and standardized baselines >>

Project Activity I

The project activity is a biomass based co-generation system set to cater the electricity and steam demand of the plant. It replaced the baseline technology fossil fuel fired traditional co-generation system that used non-renewable fuel or more carbon intensive fuel sources i.e. Coal
This project will result in avoidance of GHG emissions associated with generation of equivalent amount of energy from a coal based captive co-generation plant. Moreover, the proposed project activity will also utilize the biomass which is a renewable source of energy and thus will prevent depletion of non-renewable natural resources like coal.
Here, the project activity is to install one 8 TPH biomass fired boiler and a turbo-alternator set to cater the electricity and steam demand of the plant.

Applicability of AMS – I.C.	Project Status
3. Biomass-based cogeneration and trigeneration systems are included in this category.	**Applicable and Fulfilled** The project involves biomass (renewable) based co-generation of thermal and electrical energy for captive usage, thereby displacing fossil fuel-based cogeneration for the purpose.
4. Emission reductions from a biomass cogeneration or trigeneration system can accrue from one of the following activities: (a) Electricity supply to a grid; (b) Electricity and/or thermal energy production for on-site consumption or for consumption by other facilities; (c) Combination of (a) and (b).	**Applicable and Fulfilled** The project involves simultaneous generation of electricity and thermal energy through biomass based cogeneration plant for captive usage. Hence, point (b) fulfilled.
5. Project activities that seek to retrofit or modify an existing facility for renewable energy generation are included in this category	**Not Applicable** Project activity is a Greenfield project activity and does not seek to retrofit or modify an existing facility for renewable energy generation.

6. In the case of new facilities (Greenfield projects) and project activities involving capacity additions the relevant requirements related to determination of baseline scenario provided in the "General guidelines for SSC CDM methodologies" for Type-II and Type-III Greenfield/capacity expansion project activities also apply.	**Applicable and Fulfilled** This project activity is installation of a Greenfield cogeneration unit. Compliance with the "General Guidelines to SSC CDM methodologies" has been demonstrated at relevant places throughout the PCN.
7. The total installed/rated thermal energy generation capacity of the project equipment is equal to or less than 45 MW thermal (see paragraph 9 for the applicable limits for cogeneration and trigeneration project activities).	**Applicable and Fulfilled** This is a cogeneration project and the rated thermal energy generation capacity of the boiler is 4.97 MW_{th} which is less than 45 MWth.
8. For co-fired 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 (see paragraph 9 for the applicable limits for cogeneration project activities).	**Not Applicable** This project activity is solely renewable biomass-based co-generation project. Plant would not use any fossil fuel in its entire operating period.
9. The following capacity limits apply for biomass cogeneration and trigeneration units: (a) If the emission reductions of the project activity are on account of thermal and electrical energy production, the total installed thermal and electrical energy generation capacity of the project equipment shall not exceed 45 MW thermal. For the purpose of calculating the capacity limit the conversion factor of 1:3 shall be used for converting electrical energy to thermal energy (i.e. for renewable energy project activities, the installed capacity of 15 MW(e) is equivalent to 45 MW thermal output of the equipment or the plant); (b) If the emission reductions of the project activity are solely on account of thermal energy production (i.e. no emission reductions accrue from the electricity component), the total installed thermal energy production capacity of the project equipment shall not exceed 45 MW thermal; (c) If the emission reductions of the project activity are solely on account of electrical energy	**Applicable and Fulfilled** This is a cogeneration project, i.e., plant would extract electrical as well as thermal energy from the project activity. Total energy generation capacity of the boiler is 4.97 MW thermal which is well below the methodological capacity limit of 45 MW thermal.

production (i.e. no emission reductions accrue from the thermal energy component), the total installed electrical energy generation capacity of the project equipment shall not exceed 15 MW.	
10. The capacity limits specified in paragraphs 7 to 9 above apply to both new facilities and retrofit projects. 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 shall comply with capacity limits specified in the paragraphs 7 to 9, and shall be physically distinct from the existing units.	**Not Applicable** This project activity is solely renewable biomass based greenfield co-generation project. Addition or expansion is not applicable for this project. Compliance with the stipulated capacity limits have been demonstrated in above paragraphs.
11. If solid biomass fuel (e.g. briquette) is used, it shall be demonstrated that it has been produced using solely renewable biomass and all project or leakage emissions associated with its production shall be taken into account in the emissions reduction calculation.	**Not Applicable** The project activity does not involve use of solid biomass fuel such as briquette. It uses renewable biomasses, which is obtained from their own operations or and hence this criterion is not applicable.
12. Where the project participant is not the producer of the processed solid biomass fuel, the project participant and the producer are bound by a contract that shall enable the project participant to monitor the source of the renewable biomass to account for any emissions associated with solid biomass fuel production. Such a contract shall also ensure that there is no double-counting of emission reductions	**Not Applicable** As mentioned against criterion 9 above, the project activity does not involve use of any processed solid biomass fuel, but renewable biomass is used. Therefore no separate solid biomass fuel production process or emissions thereof are associated. Hence this criterion is not applicable.
13. If electricity and/or thermal energy 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.	**Not Applicable** The electricity and steam produced by the project activity shall be used for in-house consumption and is not delivered to another facility or facilities within the project boundary.
14. If the project activity recovers and utilizes biogas for producing electricity and/or thermal energy and applies this methodology on a standalone 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 as per relevant procedures in the tool “Emissions from solid waste disposal sites” and/or “Project	**Not Applicable** The project activity does not involve use of biogas as fuel and hence this criterion is not applicable.

emissions from flaring”. In the event that the biomass fuel (solid/liquid/gas) is sourced from an existing CDM project, then the emissions associated with the production of the fuel shall be accounted with that project.	
15. If project equipment contains refrigerants, then the refrigerant used in the project case shall have no ozone depleting potential (ODP).	**Not Applicable** The project activity does not use such equipment, which contains refrigerants. Hence this criterion is not applicable.
16. Charcoal based biomass energy generation project activities are eligible to apply the methodology only if the charcoal is produced from renewable biomass sources, provided: (a) Charcoal is produced in kilns equipped with methane recovery and destruction facility; or (b) If charcoal is produced in kilns not equipped with a methane recovery and destruction facility, methane emissions from the production of charcoal shall be considered. These emissions shall be calculated as per the procedures defined in the approved methodology “AMS-III.K: Avoidance of methane release from charcoal production by shifting from traditional open-ended methods to mechanized charcoaling process”. Alternatively, conservative emission factor values from peer reviewed literature or from a registered CDM project activity can be used, provided that it can be demonstrated that the parameters from these are comparable e.g. source of biomass, characteristics of biomass such as moisture, carbon content, type of kiln, operating conditions such as ambient temperature.	**Not Applicable** The project activity does not use charcoal for its operation. Hence this criterion is not applicable.
17. In the case the project activities utilizes biomass, the “TOOL16: Project and leakage emissions from biomass” shall be applied to determine the relevant project emissions from the cultivation of biomass and the utilization of biomass or biomass residues.	**Not Applicable** The biomass that would be used for this project would not be sourced from dedicated plantation. Project and leakage emission for utilization of biomass or biomass residue is demonstrated in the relevant place of the PCN as per Tool-16.

Project Activity II

The project will apply the UNFCCC approved methodology AMS-III.H Methane recovery in wastewater treatment, version 19.0.
This methodology refers to the following tools:

- Project emissions from flaring
- Baseline, project and/or leakage emissions from electricity consumption and monitoring of electricity generation
- Tool to calculate project or leakage CO2 emissions from fossil fuel combustion
- Emissions from solid waste disposal sites

- Positive list of technologies

Applicability of AMS – III.H.	Project Status
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 a wastewater treatment plant without sludge treatment; c) Introduction of biogas recovery and combustion to a sludge treatment system; d) Introduction of biogas recovery and combustion to an anaerobic wastewater treatment system such as anaerobic reactor, lagoon, septic tank or an on-site 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).	**Applicable and Fulfilled** The project activity involves the installation of covered lagoons and the capture and combustion of methane. The simplified baseline methodology is applicable to this project activity because without the project activity, methane from the existing anaerobic treatment system would continue to be emitted into the atmosphere. Sludge treatment remains as the pre-project situation with sludge disposition through soil application. The methodology applies "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)"
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; (b) Ambient temperature above 15^0C, 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.	**Applicable and Fulfilled** a) Lagoon depth without aeration is greater than 2 meters. b) The project is located in Karnataka province, Average temperatures exceed 15^0C in every month. c) The minimum interval between sludge removal events was at intervals greater than 30 days.
The recovered biogas from the above measures may also be utilised for the following applications instead of	**Applicable and Fulfilled**

combustion/flaring: a) Thermal or mechanical, electrical energy generation directly; b) Thermal or mechanical, electrical energy generation after bottling of upgraded biogas, in this case additional guidance provided in the appendix shall be followed; or c) Thermal or mechanical, electrical energy generation after upgrading and distribution, in this case additional guidance provided in the appendix 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 applications after upgrading.	The recovered biogas will be utilized for electrical energy generation in the drying system of the starch factory.
If the recovered biogas is used for project activities covered under paragraph 4(a), that component of the project activity can use a corresponding methodology under Type I.	**Applicable and Fulfilled** Biogas is used for electricity generation which will be used for captive consumption. Hence methodology AMS-I.F is applicable.
For project activities covered under paragraph 4(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 CO_2 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”	**Not applicable.**
For project activities covered under paragraph 4(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.	**Not applicable.**
For project activities covered under paragraph 4(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.	**Not applicable.**
In particular, for the case of paragraph 4(b) and (c)(iii), the	**Not applicable.**

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 18 of the appendix of “AMS-III.H.: Methane recovery in wastewater treatment” shall be followed in this regard.	Biogas generated would be used for electricity generation in the plant premises. Hence, transportation of biogas is not applicable for this project activity.
For project activities covered under paragraph 4(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 per cent (by volume).	**Not applicable.** The upgraded methane content of the biogas is not in accordance with relevant national regulations (where these exist) or, in the absence of national regulations, a minimum of 96 per cent (by volume). Hence, this is not applicable
If the recovered 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”.	**Not applicable.** The recovered is not utilized for the production of hydrogen. Hence, this is not applicable.
If the recovered biogas is used for project activities covered under paragraph 4(e), that component of the project activity shall use corresponding methodology “AMS-III.AQ.: Introduction of Bio-CNG in transportation applications”.	**Not applicable**. The project activity does not involves production of Bio-CNG. Hence, it is not applicable for this project activity.
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 for 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.	**Applicable and Fulfilled** As the project involves installation of a new wastewater treatment system, it will comply with all relevant requirements in the “general guidelines for SSC CDM Methodologies”. Hence, this criterion is applicable.
The location of the wastewater treatment plant as well as the source generating the wastewater shall be uniquely defined and described in the PCN.	**Applicable and Fulfilled** The location of the project activity, including the wastewater treatment plant and the source generating the wastewater, is uniquely defined in the PCN.
Measures are limited to those that result in aggregate emissions reductions of less than or equal to 60 kt CO_2 equivalent annually from all Type III components of the project activity.	**Applicable and Fulfilled** The estimated annual ERs are less than the 60,000 tCO_2 limit for Type III components.
Applicability of AMS – I.F.	**Project Status**
This methodology is applicable for project activities that: (a) Install a new power plant at a site where there was no renewable energy power plant operating prior to the	**Applicable and Fulfilled** The project is a installation of a biogas based genset to generate electricity by

<table>
<tr><td>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).</td><td>gainfully utilize the biogas captured in the project activity.

Before implementation of the project, plant has installed one biomass based co-generation project which is a different type of technology altogether. Hence, biogas power project can be considered as a green field project.</td></tr>
<tr><td>Illustration of respective situations under which each of the methodology (“AMS-I.D.: Grid connected renewable electricity generation”, “AMS-I.F.: Renewable electricity generation for captive use and mini-grid” and “AMS-I.A.: Electricity generation by the user”) applies is included in Table 2 below:
<table>
<tr><th></th><th>Project type</th><th>AMS-I.A</th><th>AMS-I.D</th><th>AMS-I.F</th></tr>
<tr><td>1</td><td>Project supplies electricity to a national/regional grid</td><td></td><td>√</td><td></td></tr>
<tr><td>2</td><td>Project displaces grid electricity consumption (e.g. grid import) and/or captive fossil fuel electricity generation at the user end (excess electricity may be supplied to a grid)</td><td></td><td></td><td>√</td></tr>
<tr><td>3</td><td>Project supplies electricity to an identified consumer facility via national/regional grid (through a contractual arrangement such as wheeling)</td><td></td><td>√</td><td></td></tr>
<tr><td>4</td><td>Project supplies electricity to a mini grid[5] system where in the baseline all generators use exclusively fuel oil and/or diesel fuel</td><td></td><td></td><td>√</td></tr>
<tr><td>5</td><td>Project supplies electricity to household users (included in the project boundary) located in off grid areas</td><td>√</td><td></td><td></td></tr>
</table></td><td>Applicable and Fulfilled

The installed project displaces the grid electricity consumption. Hence, AMS – I.F is applicable.</td></tr>
<tr><td>In the case of project activities that involve the capacity 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.</td><td>Not Applicable

Project activity is a Greenfield project. Hence, this criterion is not applicable.</td></tr>
<tr><td>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.</td><td>Not Applicable

Project does not involve retrofit or replacement of existing unit. Hence, this criterion is not applicable.</td></tr>
<tr><td>If the unit added 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 unit added co-fires fossil fuel, the capacity of the entire unit shall not exceed the limit of 15 MW.</td><td>Not Applicable

This is a green field project.</td></tr>
<tr><td>Combined heat and power (co-generation) systems are not eligible under this category.</td><td>Not Applicable

Project activity does not involves co-generation.</td></tr>
<tr><td>Hydro power plants with reservoirs that satisfy at least one of the following conditions are eligible to apply this methodology:</td><td>Not Applicable</td></tr>
</table>

(a) The project activity is implemented in an existing reservoir with no change in the volume of reservoir; (b) 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; (c) 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	This is a biogas-based electricity generation system. Hence, this criterion is not applicable.
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 that ensures that there is no double counting of emission reductions.	**Not Applicable** This a purely captive project and no electricity exported from the plant premises.
In the case the project activities utilizes biomass, the "TOOL16: Project and leakage emissions from biomass" shall be applied to determine the relevant project emissions from the cultivation of biomass and the utilization of biomass or biomass residues.	**Not Applicable** The project activity does not involve use of biomass or biomass residue.

B.3. Applicability of double counting emission reductions >>

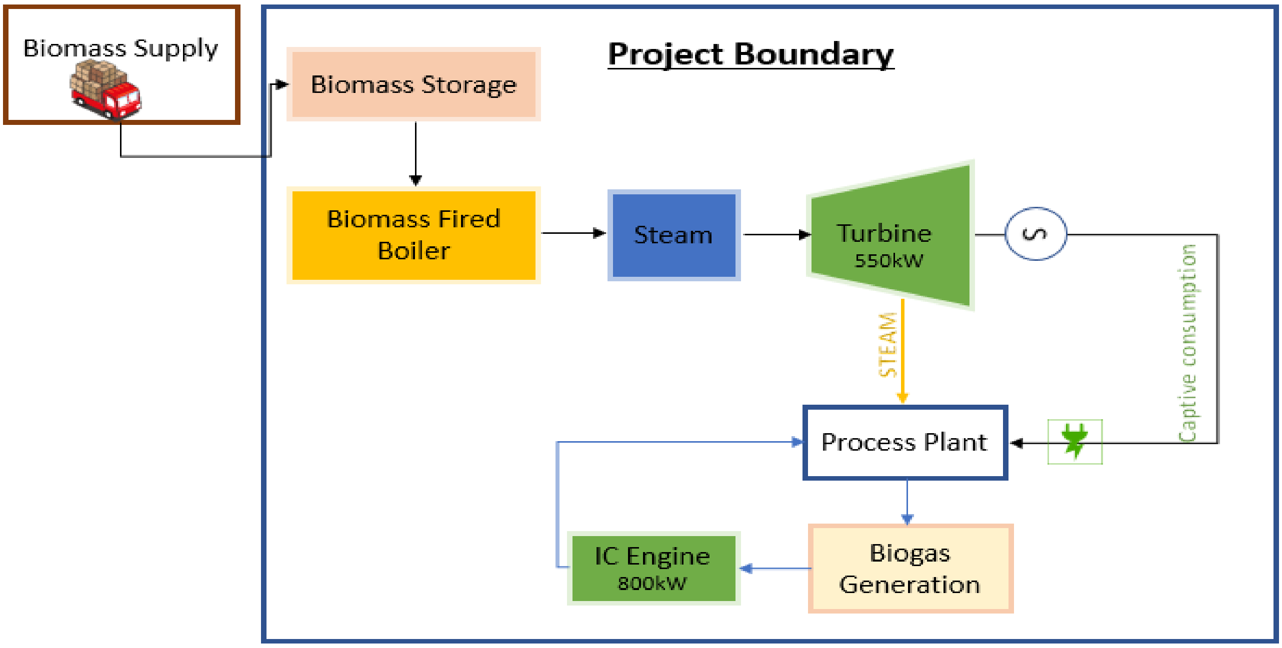
There is no double accounting of emission reductions in the project activity due to the following reasons:
• Project is uniquely identifiable based on its location coordinates,
• Project has dedicated commissioning certificate and connection point,
• Project is associated with energy meters which are dedicated to the consumption point for project developer.

B.4. Project boundary, sources and greenhouse gases (GHGs)>>

In line with the methodology, the project boundary encompasses the industrial facilities of MSIPL, which includes two project activities.

1) Project activity I
2) Project activity II

SCHEMATIC DIAGRAM SHOWING BOUNDARY



The project boundary includes the physical, geographical site(s) of:

The table below provides an overview of the emissions sources included or excluded from the project boundary for determination of baseline and project emissions.

Project I

Source		GHG	Included?	Justification/Explanation
Baseline	Coal fired co-generation for	CO_2	Included	Main Emission Source
		CH_4	Excluded	Minor Emission Source

	thermal energy and electrical energy generation	N2O	Excluded	Minor Emission Source
Project Activity	Biomass based Co-generation for thermal energy and electrical energy generation	CO2	Excluded	As the renewable biomass is carbon neutral fuel, no CO2 emitted from this project
		CH4	Excluded	Project activity does not emit CH4.
		N2O	Excluded	Project activity does not emit N2O.

Project II

	Source	GHG	Included?	Justification/Explanation
Baseline	Emissions from anaerobic digestion of effluent. Emissions from electricity imported from grid.	CO2	Included	Major source of emission
		CH4	Included	Major source of emission
		N2O	Excluded	Excluded for simplification. This is conservative
Project Activity	Emissions from on-site electricity generation. Emissions from residue from anaerobic digester composting	CO2	Excluded	Electricity is generated from collected biogas, hence these emissions are not accounted for. CO2 emissions from the decomposition of organic waste are not accounted
		CH4	Excluded	Excluded for simplification. This is conservative
		N2O	Excluded	Excluded for simplification. This is conservative

B.5. Establishment and description of baseline scenario (UCR Standard or Methodology) >>

As per the paragraph 29 of approved methodology AMS – I.C., version 22, “*Project activities producing both heat and electricity shall use one of the following baseline scenarios*”:

Baseline scenarios	**Justification for choosing the most suitable baseline option**
a) Electricity is imported from a grid and thermal energy is produced using fossil fuel;	Purchasing electricity from grid and thermal energy generation using fossil fuel may be an alternative to the project activity. However, unit cost of grid electricity in Karnataka is on higher side. Further, the state grid has shortage in power supply and power quality during peak hours get deteriorated. Thus, depending on grid-based electricity supply for operation of the plant is not a feasible option. Further, separate generation of thermal energy and purchase of grid electricity is a costlier option considering that cogeneration system is more efficient than independent heat only mode of energy

	generation. Hence, this scenario is not considered as a plausible baseline alternative.
b) Electricity is produced in an on-site captive power plant using fossil fuel (with a possibility of export to the grid) and thermal energy is produced using fossil fuel;	The combined system efficiency for separate heat and power generation would be lower compared to cogeneration plant. The captive power plant and fossil fuel-based steam generation system on account of its lower operating efficiency would result in higher fuel consumption than the cogeneration plant and hence results in higher cost of generation than the cogeneration system. Hence, this scenario is not considered as a plausible baseline alternative.
c) A combination of (a) and (b);	Since, option (a) and (b) has been eliminated, thus, this option is also not considered.
d) Electricity and thermal energy are produced in a cogeneration or trigeneration unit using fossil fuel (with a possibility of export of electricity to a grid/other facility and/or thermal energy to other facilities);	For the project activity, fossil fuel-based cogeneration unit can be a possible alternative. Abundant availability and usage of coal in the state for energy generation is a prevailing practice. Hence, this option is considered as an alternative baseline scenario for project activity.
e) Electricity is imported from a grid and/or produced in an on-site captive power plant using fossil fuels (with a possibility of export to the grid); thermal energy is produced using biomass;	As discussed against point (b) and (a) above, separate generation of energy is less efficient and more fuel consuming leading to higher cost of energy generation. Hence, this scenario is not considered as a plausible baseline alternative.
f) Electricity is produced in an on-site captive power plant using biomass (with a possibility of export to a grid) and/or imported from a grid; thermal energy is produced using fossil fuel;	As discussed against point (b) above, separate generation of energy is less efficient and more fuel consuming leading to higher cost of energy generation. Hence, this scenario is not considered as a plausible baseline alternative.
g) Electricity and thermal energy are produced in a biomass fired cogeneration or trigeneration unit (without a possibility of export of electricity either to a grid or to other facilities and without a possibility of export of thermal energy to other facilities);	As per AMS – I.C. version 22, paragraph 30, this scenario applies to a project activity that installs a new grid connected biomass cogeneration or trigeneration system that produces surplus electricity and this surplus electricity is exported to a grid. Hence, this scenario is not considered as a plausible baseline alternative
h) Electricity and/or thermal energy produced in a co-fired system;	This alternative is similar to the project option with the only difference being the provision of co-firing. Unit cost of generation with coal is lower than that using biomass, evidently the unit cost of generation in a co-fired system will be higher than a coal-based system. Hence, this scenario is not considered as a plausible baseline alternative
i) Electricity is imported from a grid and/or produced in a biomass fired cogeneration or trigeneration unit (without a possibility of export of electricity either to the grid or to other facilities); thermal energy is produced in a biomass fired cogeneration or	As discussed in bullet point (a) and (b) above, separate generation of energy is less efficient and more fuel consuming leading to higher cost of energy generation. Hence, this scenario is not considered as a plausible baseline alternative.

trigeneration unit and/or a biomass fired boiler (without a possibility of export of thermal energy to other facilities);	
j) Electricity is imported from a grid and/or produced in an on-site captive power plant using fossil fuel and thermal energy is produced using electricity.	As cost of electricity is high in Karnataka, thermal energy generation using electricity is costlier than generating thermal energy through coal-based co-gen system. Apart from that separate generation of energy is less efficient and more fuel consuming leading to higher cost of energy generation. Hence, this scenario is not considered as a plausible baseline alternative

Hence, the baseline condition for this project is Coal fired co-generation system.

Baseline Emission:

In the absence of project activity, steam and power would have been generated using coal in coal fired cogeneration unit of similar specifications. As per AMS-I.C., Version 22, paragraph 39, "*For electricity and thermal energy (steam/heat) produced in a baseline cogeneration unit, using fossil fuel (case 19 (d)), the following equation shall be used to determine baseline emissions:*"

$$BE_{cogen,CO2,y} = [(EG_{PJ,thermal,y} + EG_{PJ,electrical,y} *3.6) / \eta_{BL,cogen}] * EF_{FF,CO2}$$

Where,

$BE_{cogen,CO2,y}$ = Baseline emissions from electricity and thermal energy displaced by the project activity during the year y; tCO_{2e}

$EG_{PJ,thermal,y}$ = The net quantity of thermal energy supplied by the project activity during the year y; TJ

$EG_{PJ,electrical,y}$ = The amount of electricity supplied by the project activity during the year y; GWh

$\eta_{BL,cogen}$ = The total efficiency (including both thermal and electrical) of the cogeneration plant using fossil fuel determined in accordance with paragraphs 28 and 29 of the methodology.

$EF_{FF,CO2}$ = The CO2 emission factor of the fossil fuel that would have been used in the baseline cogeneration plant; obtained from reliable local or national data if available, alternatively, alternatively, IPCC default emission factors are used (tCO2/TJ)

Now, since the project activity plant is a Greenfield plant, therefore guidance for efficiency calculation is followed as given in paragraph 41 of AMS I.C, Version 22, which states that

"*In the case of a Greenfield project cogeneration or trigeneration plant where the baseline is a cogeneration or trigeneration plant (e.g. using a steam turbine and steam generator that would have been built in the absence of the project activity), the total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel shall be defined as the ratio of thermal energy and electricity produced to total thermal energy value of the fuel use. This ratio shall be determined using one of the two following options (in preferential order)*:

(a) Calculated as a single value with consideration of the following:

i. Step: 1

a. The total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel is determined using documented efficiency specification for new steam turbines and steam generators *provided by two or more manufacturers for each type of such equipment within in the region;*

b. *Efficiency values for the steam turbine(s) and steam generator(s) shall be based on turbines and steam generators with specifications nearly equivalent to baseline units that would have been utilized in the absence of the project activity;*

c. *The efficiency values utilized shall be the highest individual efficiency values (over the full range of expected operating conditions of the baseline cogeneration or trigeneration system) that can be achieved by the steam turbine(s) and steam generator(s).*

ii. *Step: 2*

a. *The total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel is then calculated as the product of the highest efficiency value for the steam turbine(s) and the highest efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input;*

(b) Calculated as a single value with consideration of the following:

i. *Step: 1*

a. *A default steam turbine efficiency of 100 per cent;*

b. *Default steam generator efficiency determined using the values provided in appendix;*

ii. *Step: 2*

a. *The total annual average efficiency of the cogeneration or trigeneration plant using fossil fuel is then calculated as the product of the efficiency value for the steam turbine(s) and the efficiency value of the steam generator(s), assuming both efficiencies are in the form of a percentage of output per input.*

Following option (a) of the above guidance, co-generation efficiency has been calculated by multiplying the efficiency of boiler provided by manufacturer with design efficiency of turbine.

Project Emission:

As per paragraph 66 methodology,

"Project emissions shall be calculated using the following equation:

$PE_y = PE_{FF,y} + PE_{Ec,y} + PE_{Geo,y} + PE_{ref,y} + PE_{Biomass}$

Where,

PE_y = Project emissions from the project activity during the year y (t CO2);

$PE_{FF,}$ = Project emissions from fossil fuel consumption during the year y (t CO2);

$PE_{Ec,}$ = Project emissions from electricity consumption during the year y (t CO2);

$PE_{Geo,}$ = Project emissions from a geothermal project activity in year y (t CO2);

$PE_{ref,}$ = Project emissions from use of refrigerant in project activity in year y (t CO2);

$PE_{Biomass}$ = Project emissions associated with biomass and biomass residues in year y (t CO2e)"

This is not a geothermal project. The project activity however does not envisage using any fossil fuel during the crediting period. Auxiliary power is supplied from the project itself. Hence, for ex-ante estimations project emissions due to consumption of fossil fuel and electricity consumption has been considered 0. As project does not use any refrigerant in the project activity, project emission related to refrigerant is considered as 0.

Hence, for simplification,

$PE_y = PE_{Biomass}$

As per paragraph 14 of Tool 16, "Project emissions involve emissions resulting from the cultivation of biomass, transportation of biomass, processing of biomass, transportation of biomass residues and processing of biomass residues."

Project does not have any dedicated plantation or cultivation of biomass and raw biomass is being fired in the boiler without any further processing. Hence, project emission would only be calculated for transportation of biomass residue. As per Tool 16 para 31(a), project emission would be calculated based on the default emission factor of 0.0142 t-CO2/ton of biomass.

Leakage Emission:

As per the paragraph 79 of AMS – I.C. version 22,

"*If the energy generating equipment currently being utilized is transferred from outside the boundary to the project activity, leakage is to be considered.*"

For this project activity there is no transfer of equipment and therefore leakage due to equipment transfer has been taken to be zero.

As per the paragraph 80 of AMS – I.C. version 22,

"*If the displaced refrigerant is a greenhouse gas as defined in annex A of the Kyoto Protocol or in paragraph 1 of the Convention and is not destroyed, emissions from its storage or usage in equipment must be considered as leakage*."

In the project scenario, displacement and storage of refrigerant is not relevant for this project. Hence, this criterion is not applicable.

As per the paragraph 81 of methodology,

"*For project activities utilizing biomass and/or biomass residues, the TOOL16 shall be applied to determine the leakage. Project participants shall indicate in the PDD which leakage sources are included. If emission sources are not considered, the project participants shall provide proper justification in the PDD"*

As per the paragraph 49 of Tool 16 Methodological tool: Leakage in biomass small-scale project activities Version 04.0

"*This section is applicable for project activities which utilise biomass residues. It quantifies leakage due to diversion of biomass residues to the project to be used as either fuel or feedstock. These biomass residues could have been used outside the project boundary in competing applications, and due to the implementation of the project activity these competing application might be forced to use inputs which are not carbon neutral.*"

In the project scenario, biomass residues being used as fuel is purchased by the project activity and transported from the nearby areas. Round trip distance for transportation of biomass is less than 200 km. As biomass is surplus near the project location, there is no leakage from competing uses of biomass.

The key parameters for baseline emission calculation are presented below in a tabular format: -

Parameter	Unit	Value
Steam to turbine	Tph	8
Back pressure steam	Tph	5

Electricity generation capacity of project	MW	0.55
Coal emission factor ($EF_{FF,CO2}$) (mixed power plant)	tCO_2/TJ	96.1
Operating days	Days	247
Operating hours	Hours	24
Efficiency of boiler using coal	%	80 %
Pressure of steam at Boiler outlet	kg/cm2	45
Temperature of steam at Boiler outlet	Deg. C	440
Pressure of steam at Turbine Extraction	kg/cm2	5
Temperature of feed water inlet to boiler	Deg. C	98

Baseline emission (BEy)= 16,384 CoUs /year (16,384 tCO2eq/yr)
Project emission (PEy)= 273 CoUs /year (273 tCO2eq/yr)
Emission Reduction (ERy)= 16,111 CoUs /year (16,111 tCO2eq/yr)

Project Type II

Baseline Scenario
According to AMS-III.H version 19.0, the baseline scenario involves a baseline system with anaerobic wastewater treatment system without biogas recovery, which is the case here. In the absence of the project, the mill would have continued operating its wastewater treatment facility without any upgrade of technology. The baseline scenario is identified as the continuation of current situation, resulting in free release of methane into the atmosphere.

According to methodology AMS-III.H version 19.0, baseline emissions for the systems affected by the project activity may consist of:
(a) Emissions on account of electricity or fossil fuel used (BEpower,y)
(b) Methane emissions from baseline wastewater treatment systems (BEww,treatment,y);
(c) Methane emissions from baseline sludge treatment systems (BEs,treatment,y);
(d) Methane emissions on account of inefficiencies in the baseline wastewater treatment systems and presence of degradable organic carbon in the treated wastewater discharged into river/ lake/ sea (BEww,discharge,y);
(e) Methane emissions from the decay of the final sludge generated by the baseline treatment systems (BEs,final,y).

BEy = BEpower,y + BEww,treatment,y + BEs,treatment,y + BEww,discharge,y + BEs,final,y

Where:

BEy	: Baseline emissions in year y (tCO2e)
BEpower,y	: Baseline emissions from electricity or fuel consumption in year y (tCO2e)
BEww,treatment,y	: Baseline emissions of the wastewater treatment systems affected by the project activity in year y (tCO2e)
BEs,treatment,y	: Baseline emissions of the sludge treatment systems affected by the project activity in year y (tCO2e)
BEww,discharge,y	: Baseline methane emissions from degradable organic carbon in treated wastewater discharged into sea/river/lake in year y (tCO2e).
BEs,final,y	: Baseline methane emissions from anaerobic decay of the final sludge produced in year y (tCO2e). If the sludge is controlled combusted, disposed in a landfill with biogas recovery, or used for soil application in the baseline scenario, this term shall be neglected.

In the project case:
- the electric consumption of wastewater treatment is the same in the baseline and project situation.
- there is no sludge treatment in the baseline and in the project situation

- Plant has adopted ZLD system and no treated effluent is discharged into sea/river/lake.
- Final sludge is used for soil application as a bio manure.

The system affected is only the baseline wastewater treatment system. Therefore, equation (1) can be reduced to:

$$BE_y = BE_{ww,treatment,y} \qquad \text{Equation (1b)}$$

Methane emissions from the baseline wastewater treatment systems affected by the project ($BE_{ww,treatment,y}$) are determined using the COD removal efficiency of the baseline plant as follows:

$$BE_{ww,treatment,y} = \Sigma i \, (Q_{ww,i,y} \times COD_{inflow,i,y} \times \eta_{COD,BL,i} \times MCF_{ww,treatment,BL,i}) \times B_{o,ww} \times UF_{BL} \times GWP_{CH4} \qquad \text{(Eq 2)}$$

Where:

$Q_{ww,i,y}$	Volume of wastewater treated in baseline wastewater treatment system i in year y (m3). For ex ante estimation, forecasted wastewater generation volume or the designed capacity of the wastewater treatment facility can be used. However, the ex post emissions reduction calculation shall be based on the actual monitored volume of treated wastewater
$COD_{inflow,i,y}$	Chemical oxygen demand of the wastewater inflow to the baseline treatment system i in year y (t/m3). Average value may be used through sampling with the confidence/precision level 90/10. Monitored values of the COD inflow during crediting period will be used to calculate the baseline emissions ex post
$\eta_{COD,BL,i}$	COD removal efficiency of the baseline treatment system i
$MCF_{ww,treatment,BL,i}$	Methane correction factor for baseline wastewater treatment systems i. MCF value is identified as 0.8 corresponding to anaerobic deep lagoon(depth more than 2 meters) (IPCC and methodology)
i	Index for baseline wastewater treatment system
$B_{o,ww}$	Methane producing capacity of the wastewater (IPCC value of 0.25kgCH4/kg COD)
UF_{BL}	Model correction factor to account for model uncertainties (0.89)
GWP_{CH4}	Global Warming Potential for methane

<u>Calculation of BE ww,treatment,y</u>

Parameter	**Value applied**	**Source**
$Q_{ww,i,y}$	129600 (m3)	Based on one year of historical data of the plant
$COD_{inflow,i,y}$	0.024 (t/m3)	Based on a 10-day measurement campaign
$\eta_{COD,BL,i}$	98.95 %	Calculated as detailed below

$MCF_{ww,treatment,BL,i}$	0.8	Corresponding to anaerobic deep lagoon (depth more than 2 meters)
Bo,ww	0.25 kgCH4/kg COD	Default value as per the methodology
UF_{BL}	0.89	Default value as per the methodology
GWP_{CH4}	25 tCO2/tCH4	IPCC default value

The COD removal efficiency of the baseline is calculated as:

$\eta_{COD,BL,i} = 1 – (COD_{outlow,i,y} / COD_{inflow,i,y})$ x 0.89

Where:

$COD_{inflow,i,y}$	24000 mg/l
$COD_{outlow,i,y}$	250 mg/l

$\eta_{COD,BL,i}$ = 0.9895 x 0.89= 88.07%

Methane emissions from the baseline wastewater treatment system affected by the project $BE_{ww,treatment,y}$ are thus calculated as 15,341 tCO2e/year.

Project Emission:

According to the methodology, project emissions may consist of:

(a) CO2 emissions from electricity and fuel used by the project facilities ($PE_{power,y}$),

(b) Methane emissions from wastewater treatment systems affected by the project activity, and not equipped with biogas recovery in the project scenario ($PE_{ww,treatment,y}$),

(c) Methane emissions from sludge treatment systems affected by the project activity, and not equipped with biogas recovery in the project situation ($PE_{s,treatment,y}$),

(d) Methane emissions on account of inefficiency of the project activity wastewater treatment systems and presence of degradable organic carbon in treated wastewater ($PE_{ww,discharge,y}$),

(e) Methane emissions from the decay of the final sludge generated by the project activity treatment systems ($PE_{s,final,y}$),

(f) Methane fugitive emissions due to inefficiencies in capture systems ($PE_{fugitive,y}$),

(g) Methane emissions due to incomplete flaring ($PE_{flaring,y}$),

(h) Methane emissions from biomass stored under anaerobic conditions which would not have occurred in the baseline situation ($PE_{biomass,y}$)

It is expected that electricity consumed for the operation of the project activity including biogas recovery will be sourced from on-site power generation from biogas. The project activity does not involve project emissions from (c) (d) (e) (h).

$PE_{ww,treatment,y}$ is not applicable because the wastewater treatment system affected by the project activity will be equipped with biogas recovery in the project scenario.

Thus, project emissions consist of:

$PE_y = PE_{fugitive,y} + PE_{flaring,y}$ Equation(3)

Where:

PE_y :Project activity emissions in the year y (t CO2e)

$PE_{fugitive,y}$:Methane emissions from biogas release in capture systems in year y (tCO_2e)

$PE_{flaring,y}$:Methane emissions due to incomplete flaring in year y (tCO_2e).

<u>Equations used for the calculation of $PE_{fugitive,y}$</u>

Project activity emissions from methane release in capture systems are determined as follows:

(a) Based on the methane emission potential of wastewater:

$PE_{fugitive,y} = PE_{fugitive,ww,y}$ Equation (5)

Where:

$PE_{fugitive,ww,y}$ Fugitive emissions through capture inefficiencies in the anaerobic wastewater treatment systems in the year y (tCO_2e)

$PE_{fugitive,ww,y} = (1 – CFE_{ww})$ x $MEP_{ww,treatment,y}$ x GWP_{CH4} Equation (6)

Where:

CFE_{ww} Capture efficiency of the biogas recovery equipment in the wastewater treatment systems (a default value of 0.9 shall be used)

$MEP_{ww,treatment,y}$ Calculated as 689.47 tCH_4 (see details below)

$$\mathbf{MEP_{ww,treatment,y} = Q_{ww,y} \times B_{o,ww} \times UF_{BL} \times \Sigma_k COD_{removed,PJ,k,y} \times MCF_{ww,treatment,PJ,k}}$$ Equation (7)

Where:

Parameter	**Value applied**	**Source**
$Q_{ww,i,y}$	129600 (m3)	Based on one year of historical data of the plant
$COD_{removed,PJ,k,y}$	0.026 (t/m3)	Based on a 10-day measurement campaign
$MCF_{ww,treatment,BL,i}$	0.8	Corresponding to anaerobic deep lagoon (depth more than 2 meters)
Bo,ww	0.25 kgCH4/kg COD	Default value as per the methodology
UF_{BL}	0.89	Default value as per the methodology
GWP_{CH4}	28 tCO2/tCH4	IPCC default value

$COD_{removed,PJ,k,y}$ is the difference between $COD_{inflow,PJ,y}$ and $COD_{outflow,PJ,y}$ of the treatment system installed in the Project.

Inflow and outflow of COD are regularly measured and monitored by project proponent. The values applied for ex-ante calculations of project emissions are the average values of COD_{inflow} and $COD_{outflow}$.

Where:

CODinflow,i,y	24000 mg/l
CODoutlow,i,y	250 mg/l
$COD_{removed,PJ,k,y}$	23750 mg/l

Therefore, $PE_{fugitive,ww,y}$ = (1 – 0.9) x 689.47 x 28 = 1,930.52 tCO_2

Flaring

Project emissions due to incomplete flaring are expected to be zero because all biogas recovered will be combusted in the gensets. If there is not enough gas to power the genset, the digester will remain shut off until there is enough gas accumulated.
Therefore, $PE_{flaring,y}$ is assumed to be zero .

Ex-ante annual estimates of project emissions are calculated as PE_y = 1,930.52 tCO_2.

Leakage

No leakage emissions need to be accounted unless if the technology is using equipment transferred from another activity, which is not the case here.

Net GHG Emission Reductions and Removals

$ER_{y,exante} = BE_{y,exante} - PE_{y,exante}$
Equation (8)

Where:

$ER_{y,exante}$ Ex ante emission reduction in year y (tCO_2e)

$BE_{y,exante}$ Ex ante baseline emissions in year y (tCO_2e)

$PE_{y,exante}$ Ex ante project emissions in year y (tCO_2e)

Therefore, $ER_{y,exante=}$ 13,410 tCO_2e/annum

Baseline Scenario
According to AMS-I.F, the project activity includes electricity generation from the renewable power plant to the captive use/ end users/. And, hence the renewable power plant can be considered as the installation of new off grid-connected renewable power plant that supply the electricity to end user, which is fed by both fossil fuel fired generating plants (using fossil fuels such as coal, natural gas, diesel, naphtha etc.) and non-fossil fuel based generating plants (such as hydro, nuclear, biomass and wind). Hence, the applicable baseline, as per the approved methodology AMS-I.F, the baseline of the project activity is the “kWh produced by the renewable generating unit multiplied by an emission coefficient (measured in kg CO2e/kWh) calculated in a transparent and conservative manner.
According to AMS-I.F v4.0, baseline emissions from electricity displacement are calculated as follows:

Baseline emissions for other systems are the product of amount electricity displaced with the electricity produced by the renewable generating unit and an emission factor.

$BE_y = EG_{BL}, \times EF_{CO2,y}$

Where:

BEy	Baseline emissions in year y (t CO2)
$EGBL,y$	Quantity of net electricity displaced as a result of the implementation of the project activity in year y (MWh)
$EFCO2,y$	Emission factor (t CO2/MWh) • The emission factor of an electric grid shall be calculated as per the procedures provided in AMS-I.D.; • For a mini-grid system other than described in paragraph 18 above, the baseline emission factor shall be determined as per the weighted average emissions for the current generation mix following the procedure provided in AMS-I.D.; • The emission factor for captive electricity generation shall be calculated as per the procedures described in the latest version of the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption”

EG_{BL}, = Quantity of net electricity generation/supplied by the project plant/unit= 4736 MWh

Baseline emission reductions (BEy)= 4305 tCO2/annum

Estimated Annual or Total baseline emission reductions (BEy) = 33,826 CoUs /year (33,826 tCO2eq/yr)

B.6. Prior History>>

The project activity has not applied to any other GHG program for generation or issuance of carbon offsets or credits for the said crediting period.

B.7. Changes to start date of crediting period >>

The crediting period under UCR has been considered from the date of commissioning of the project.

B.8. Permanent changes from PCN monitoring plan, applied methodology or applied standardized baseline >>

There are no permanent changes from registered PCN monitoring plan and applied methodology.

B.9. Monitoring period number and duration>>

First Issuance Period: 9 years, 8 months – 18/01/2013 to 18/09/2022

B.8. Monitoring plan>>

Following parameters being used in emission reductions determination (Fixed Ex-Ante):

Data/Parameter	$\eta_{BL,cogen}$
Data unit	%
Description	Co-generation efficiency of baseline project
Source of data	Boiler Specification Sheet and actual calculated turbine efficiency.

Value(s) applied	
Measured / Calculated/ Default	Calculated based on the boiler and turbine efficiency. Co-gen efficiency = boiler efficiency X turbine efficiency.
Value of Monitored parameter	48.39%
Measurement methods and procedures	N/A
Monitoring frequency	The value is fixed for entire crediting period
Purpose of data	To calculate baseline emission.

Data / Parameter:	$\mathbf{EF_{FF,CO2,coal}}$
Data unit:	t-CO_{2e}/TJ
Description:	The CO2 emission factor per unit of energy of the fuel (coal) that would have been used in the baseline plant
Source of data Value (s) applied	As per Table 2.2, Chapter-2, Volume-2, IPCC 2006 guidelines
Measured / Calculated/ Default	Default
Value of Monitored parameter	96.1
Measurement procedures (if any):	N/A
Monitoring frequency:	This value is fixed for entire crediting period

Data/Parameter	$MCF_{ww,treatment,BL,i}$
Data unit	Factor
Description	Methane correction factor for baseline wastewater treatment systems i
Source of data	MCF values as per Table 2 of AMS-III.H. V.19
Value(s) applied	0.8
Measurement methods and procedures	IPCC default value applies
Purpose of data	Calculation of baseline emissions
Comments	-

Data/Parameter	$\eta_{COD,BL,i}$
Data unit	%
Description	COD removal efficiency of the baseline treatment system
Source of data	Third party measurements and calculations in line with AMS-III.H
Value(s) applied	98.96%
Measurement methods and procedures	Calculated Value
Purpose of data	Calculation of baseline emissions
Comments	-

Data/Parameter	$B_{o,ww}$
Data unit	CH4/kg COD
Description	Methane producing capacity of the wastewater
Source of data	IPCC default value
Value(s) applied	0.25
Measurement methods and procedures	IPCC default value applies in line with Equation 2 of AMS-III.H V.19
Purpose of data	Calculation of baseline methane emissions
Comments	-

Data/Parameter	UF_{BL}
Data unit	Factor
Description	Model correction factor to account for model uncertainties (0.89)
Source of data	AMS-III.H v 19
Value(s) applied	0.89
Measurement methods and procedures	As specified in methodology
Purpose of data	Calculation of baseline emissions
Comments	Reference: FCCC/SBSTA/2003/10/Add.2, page 25

Data/Parameter	GWP_{CH4}
Data unit	tCO_2e/tCH_4
Description	Global Warming Potential for methane
Source of data	IPCC default values
Value(s) applied	28
Measurement methods and procedures	IPCC data used
Purpose of data	GWPCH4
Comments	tCO2e/tCH4

Following parameters being monitored for emission reductions determination:

Data / Parameter:	**$EG_{PJ, electrical, y}$**
Data unit:	MWh/year
Description:	Amount of electricity supplied by the project activity - I in year y
Source of data:	Onsite measurement
Measurement procedures (if any):	Measurement would be done by installing 3 phase energy meter at HT side or LT side of generation end.
Monitoring frequency:	Monitoring procedure: Continuously with energy meters Data Type: measured Recording frequency: Daily / Monthly Consolidated Archiving method: Electronic
QA/QC procedures:	Installed energy meter would be as per national or IEC standard. Calibration would be carried out once in every five years.

Any comment:	Generation data would be archiving electronically up to 2 years from the end of crediting period.

Data / Parameter:	$\mathbf{T_{FW}}$
Data unit:	^{O}C
Description:	Average temperature of feed water at boiler inlet.
Source of data:	Onsite measurement
Measurement procedures (if any):	Measurement would be done by installed thermometer.
Monitoring frequency:	Monitoring procedure: Continuously with installed thermometer Data Type: measured Recording frequency: Daily average / monthly average Archiving method: Electronic
QA/QC procedures:	Temperature Gauge will be standard make and recalibrated at appropriate intervals according to manufacturer specifications. If any malfunction noticed, meter would be change with immediate effect.
Any comment:	Data would be archiving electronically up to 2 years from the end of crediting period.

Data/Parameter	$\mathbf{E_{FW}}$
Data unit	kJ/kg
Description	Average enthalpy of feed water at boiler inlet.
Source of data	Steam Table
Measurement procedures	N/A
Monitoring frequency	Monitoring procedure: Continuously from measured temperature of feed water. Data Type: Calculated Archiving method: Electronic
QA/QC procedures	As value would be calculated from steam table, data would be authentic.
Any comment:	Data would be used to evaluate enthalpy change in boiler

Data/Parameter	$\mathbf{Q_{steam}}$
Data unit	MT/Year
Description	Extracted steam supplied to process plant in the year y
Source of data	Onsite Measurement
Measurement procedures	Net steam delivered = Present Reading – Previous Reading Archiving method: Electronic
Monitoring frequency	Monitoring procedure: Daily from installed Steam flow meter. Data Type: Calculated Calculation method: Calculated by subtracting previous reading from present reading of steam flow meter reading.
QA/QC procedures	Steam flow meter will be certified by third party as per national or international standards and recalibrated at appropriate intervals according to manufacturer specifications.
Any Comment	Data would be used to evaluate net quantity of thermal energy delivered by the project and would be archiving electronically up to 2 years from the end of

	crediting period.

Data / Parameter:	$\mathbf{P_{process}}$
Data unit	Kg/cm^2 (g)
Description	Pressure of steam bleed extracted from turbine to supply to the process.
Source of data	Onsite Measurement
Measurement procedure	Measurement would be done by installed pressure gauge.
Measuring frequency	Monitoring procedure: Daily from installed pressure gauge. Data Type: Calculated Recording frequency: Daily Average Archiving method: Electronic
QA/QC procedures	Pressure gauge will be certified by third party as per national or international standards and recalibrated at appropriate intervals according to manufacturer specifications;
Any Comment	To evaluate the enthalpy of the steam bleed.

Data / Parameter:	$\mathbf{E_{steam}}$
Data unit	kJ/kg
Description	Enthalpy of extracted steam
Data source	Steam Table
Measurement Procedure	N/A
Measuring frequency	Monitoring procedure: Continuous. Data Type: Calculated Recording frequency: Daily Average / monthly average Archiving method: Electronic
QA/QC procedures	As data would obtain from Steam Table, no need any QA/QC.
Any Comment	Data would be used to evaluate enthalpy of the steam

Data / Parameter:	$\mathbf{B_{biomass,y}}$
Data unit	Tonne/Year
Description	Quantity of biomass combusted in an year y
Data source	Onsite measurement
Measurement Procedure	Measurement would be done for each batch of purchased biomass during the entry inside the plant by installed mechanical weighbridge. Net biomass consumption can be calculated by subtracting closing stock of biomass from opening stock of biomass.
Measuring frequency	Monitoring procedure: for each batch of purchased biomass. Data Type: Measured Recording frequency: Daily / Monthly Average Archiving method: Electronic
QA/QC procedures	Consumption of biomass can be cross checked by comparing purchased quantity from invoices and by conducting energy balance.
Any Comment	To cross check energy generation.

Data / Parameter:	GCV_k
Data unit	Kcals/kg
Description	Gross calorific value of biomass combusted in an year y

Data source	Lab test report
Measurement Procedure	Value can be obtained by testing the biomass sample from third party lab quarterly for first crediting period and the average value would be fixed for entire crediting period..
Measuring/reading/ recording frequency	Measuring procedure: Quarterly for first year of the crediting period. Data Type: Calculated Archiving method: Electronic
QA/QC procedures	Biomass sample would be sent to external lab for testing. Testing would be done quarterly for first crediting period. Average of the measured GCV of first crediting period would be fixed for entire crediting period.
Any Comment	To cross check energy generation.

Data/Parameter	$Q_{ww,i,y}$
Data unit	m^3
Description	Flow of wastewater entering (inflow) the anaerobic digester
Source of data	On-site measurement
Measurement methods and procedures	Measurements will be taken using flowmeter(s) at inlet of the anaerobic digester
Frequency of monitoring/recording	Monitored continuously (at least hourly measurements are undertaken,)
Value applied	9600 m^3/day used for ex-ante estimates
Monitoring equipment	Flow Meter
QA/QC Procedures to be applied	Flowmeter(s) to be maintained according to manufacturer's specifications
Purpose of data	Calculation of baseline emissions Calculation of project emissions
Calculation method	N/A
Comments	-

Data/Parameter	$COD_{ww,inflow,y}$
Data unit	tCOD/m3
Description	Chemical Oxygen Demand of the wastewater entering (inflow) the anaerobic digester
Source of data	On-site measurement
Measurement methods and procedures	Measure the COD according to national or international standards. COD is measured through representative sampling.
Frequency of monitoring/recording	Periodically
Value applied	0.024 used for ex-ante estimates
Monitoring equipment	Laboratory analysis
QA/QC Procedures to be applied	Samples and measurements shall ensure a 90/10 confidence/precision level
Purpose of data	Calculation of baseline emissions and project emissions
Calculation method	N/A
Comments	-

Data/Parameter	$COD_{ww,outflow,y}$
Data unit	tCOD/m3
Description	Chemical Oxygen Demand of the wastewater at the outlet (outflow) of the anaerobic digester
Source of data	On-site measurement
Measurement methods and procedures	Measure the COD according to national or international standards. COD is measured through representative sampling.
Frequency of monitoring/recording	Periodically
Value applied	0.00025 used for ex-ante estimates
Monitoring equipment	Laboratory analysis
QA/QC Procedures to be applied	Samples and measurements shall ensure a 90/10 confidence/precision level
Purpose of data	Calculation of baseline emissions and project emissions
Calculation method	N/A
Comments	-

Data/Parameter	$BG_{burnt,y}$
Data unit	m^3
Description	Biogas volume in year y
Source of data	On-site measurement
Measurement methods and procedures	In all cases, the amount of biogas recovered, fuelled or flared shall be monitored ex post, using continuous flow meters. If the biogas streams flared and fuelled (or utilized) are monitored separately, the two fractions can be added together to determine the total biogas recovered, without the need to monitor the recovered biogas before the separation. The methane content measurement shall be carried out close to a location in the system where a biogas flow measurement takes place
Frequency of monitoring/recording	Monitored continuously
Value applied	Value not used for ex-ante estimates, to be monitored ex-post
Monitoring equipment	Flow meter(s)
QA/QC Procedures to be applied	Flowmeter(s) to be maintained according to manufacturer's specifications and would be crosschecked w.r.t. effluent coming to digester and generated electricity by the gas.
Purpose of data	Calculation of baseline emissions
Calculation method	N/A
Comments	-

Data/Parameter	$W_{CH4,y}$
Data unit	%
Description	Methane content in biogas in year y
Source of data	On-site measurement
Measurement methods and procedures	The fraction of methane in the gas should be measured with a continuous analyser or, alternatively, with periodical measurements at a 90/10 confidence/precision level. It shall be measured using equipment that can directly measure methane content in the biogas - the estimation of methane content of biogas based on measurement of other constituents of biogas such as CO2 is not permitted. The methane content measurement shall be carried out close to a location in the system where a biogas flow measurement takes place.
Frequency of monitoring/recording	Monitored continuously (at least hourly measurements are undertaken, if less, confidence/precision level of 90/10 shall be attained)
Value applied	Value not used for ex-ante estimates, to be monitored ex-post
Monitoring equipment	Gas analyzer(s)
QA/QC Procedures to be applied	Gas analyzer(s) to be maintained according to manufacturer's specifications
Purpose of data	Calculation of baseline emissions
Calculation method	N/A
Comments	-

Data/Parameter	T
Data unit	^{O}C
Description	Temperature of the biogas
Source of data	On-site measurement
Measurement methods and procedures	The temperature of the gas is required to determine the density of the methane combusted. If the biogas flow meter employed measures flow, pressure and temperature and displays or outputs the normalised flow of biogas, then there is no need for separate monitoring of pressure and temperature of the biogas.
Frequency of monitoring/recording	Shall be measured at the same time when the flow of biogas is measured.
Value applied	Value not used for ex-ante estimates, to be monitored ex-post
Monitoring equipment	Temperature sensor(s)
QA/QC Procedures to be applied	Temperature sensor(s) to be maintained according to manufacturer’s specifications
Purpose of data	Calculation of baseline emissions
Calculation method	N/A
Comments	-

Data/Parameter	P
Data unit	Pa
Description	Pressure of the biogas
Source of data	On-site measurement
Measurement methods and procedures	The pressure of the gas is required to determine the density of the methane combusted. If the biogas flow meter employed measures flow, pressure and temperature and displays or outputs the normalised flow of biogas, then there is no need for separate monitoring of pressure and temperature of the biogas.
Frequency of monitoring/recording	Shall be measured at the same time when the flow of biogas is measured.
Value applied	Value not used for ex-ante estimates, to be monitored ex-post
Monitoring equipment	Pressure sensor(s)
QA/QC Procedures to be applied	Pressure sensor(s) to be maintained according to manufacturer’s specifications
Purpose of data	Calculation of baseline emissions
Calculation method	N/A
Comments	-

Data/Parameter	$EF_{CO2,y}$
Data unit	tCO_2/MWh
Description	The emission factor of an electric grid shall be calculated as per the procedures provided in AMS-I.D;
Source of data	Central Electricity Authority (CEA) Database, 2022.
Measurement methods and procedures	Combined Margin Emission Factor has been considered as per the provision of EF calculation under the methodology prescription as per Tool 7
Value applied	0.90
Purpose of data	Calculation of baseline emissions
Comments	N/A

Data/Parameter	$EG_{BL,y}$
Data unit	MWh/year
Description	Quantity of net electricity displaced in year y
Source of data	Plant records, electronic records
Measurement methods and procedures	Quantity of electricity generated by gas engine shall be measured using an energy meter to be installed at the plant level and records are kept on electronically.
Frequency of monitoring/recording	Continuous monitoring, monthly and annual aggregation
Value applied	To be considered on actual
Monitoring equipment	3 phase energy meter installed with gas engine.
QA/QC Procedures to be applied	The energy meter shall be calibrated once 3 years or as per manufacturer’s recommendation, whichever is earlier.
Purpose of data	Calculation of baseline emissions
Calculation method	N/A
Comments	The data would be archived electronically and maintained upto 2 years after the end of the entire crediting period.