CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

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Annexes

Appendices

SECTION A. General description of project activity

A.1. Title of the project activity:

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"20MW Bagasse based Cogeneration power project at Bannari Amman Sugars Limited, Sathyamangalam, Tamil Nadu by Bannari Amman Sugars Limited"

Version 04

28/06/2010

A.2. Description of the project activity:

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Purpose

BASL is a part of the Bannari Amman Group, a leading industrial conglomerate engaged in the manufacturing of sugar, industrial alcohols, granites, power generation and distribution. The project activity has been implemented in one of the sugar factories of M/s. Bannari Amman Sugars Limited (BASL) situated at Sathyamangalam, Erode District, Tamil Nadu with a crushing capacity of 4000 TCD.

The sugar plant at Sathyamangalam was operating with a crushing capacity of 2500 Tonnes Cane per Day (TCD) from year 1995. During the year 1999, considering the improved cane availability (as a result of the various cane development activities of the company in the previous years), BASL increased the crushing capacity of the sugar mill to 4000 TCD. The energy requirements of the 4000 TCD sugar plant were met by the existing low pressure cogeneration plant which had sufficient lifetime[1] and capacity[2] to continue operating.

However, considering the potential of surplus power generation and export to grid, BASL explored the option of replacing the existing system with a high pressure high efficiency system of 87 ata pressure configuration, which is the first of its kind in the region. The detailed energy and mass balance of the pre-project and project scenarios are provided in annex-3.

[1] Certificate for remaining lifetimes of the existing boilers and TGs issued by chartered engineers is submitted to DOE

[2] Refer table T3.2 in annex-3

The project activity aims to improve the efficiency of an existing cogeneration plant using biomass residues by installing a more efficient cogeneration plant that replaces the existing plant and the resulting surplus electricity is exported to the State Electricity Grid. The project proponent proposes to install one boiler of 120 TPH capacity at 87 ata pressure and 515^0C temperature using bagasse as the fuel.

Prior to implementation of the project activity, BASL was generating steam and power from its mill generated bagasse, through two low pressure boilers of capacity 30 TPH and 40 TPH and two turbo generator (TG) sets of capacity 1.5 MW and 3 MW. The generated steam and power were utilized to meet the captive energy requirements of the sugar factory.

After installation of new 20 MW high pressure cogeneration plant (“project activity”), BASL has removed the existing 4.5 MW cogeneration plant in order to improve the energy efficiency and increase power generation thereby facilitating the export of electricity to the Tamil Nadu Electricity Board (TNEB) grid, which is part of the southern regional grid of India. Hence, the project displaces fossil fuel intensive electricity from the grid connected power plants and reduces anthropogenic emission to the atmosphere.

In the absence of the project activity, BASL would continue to operate its existing 4.5 MW low pressure cogeneration system (without any significant changes) and continue to satisfy the energy requirements of the 4000 TCD sugar plant. The existing plant has sufficient lifetime to continue operating beyond the crediting period.

Project’s contribution to sustainable development

Social well-being

The project activity helps to bridge the gap of electricity demand and supply at local and national level. The location of the project activity in rural setting contributes towards poverty alleviation by generating both direct and indirect employment. The project activity generates additional income for BASL, enabling the allocation of funds to continue its social welfare measures like health camps, infrastructure development, dissemination of latest agricultural techniques etc.

Economic well-being

The project activity being situated at a remote part of the grid serves as a decentralized grid power source. The improved power quality has a direct positive impact on the region's economic growth through better productivity and quality of life. The revenues from sale of electricity would provide sufficient funds for BASL to expand its sugar crushing capacity, leading to higher cane demand that would boost local employment and improve the income level of farmers in the region.

Environmental well-being

The CO_2 emissions of the combustion process due to burning of bagasse are consumed by the sugarcane plant during its growth, representing a cyclic process, thereby leading to zero net CO_2 emission. The export of surplus electricity to the grid reduces the emission of environmentally harmful gases including GHGs from fossil fuel power plants.

Technological well-being

The project activity uses the most efficient and environment friendly technology of cogeneration available in the renewable energy sector at the time of its implementation. The successful demonstration of the high pressure (87 ata and 515ºC) cogeneration technology helps to accelerate the conversion from lesser steam parameters (32 ata) prevalent in the country to high efficiency high pressure systems.

A.3. Project participants:

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Name of Party involved (*) (host indicates 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**
India (Host Country)	Bannari Amman Sugars Limited (Private Entity)	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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A.4.1.1. Host Party(ies):

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India

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

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Tamil Nadu

A.4.1.3. City/Town/Community etc.:

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Alathukombai Village, Sathyamangalam Taluk, Erode District

A.4.1.4. Details of physical location, including information allowing the unique identification of this project activity (maximum one page):

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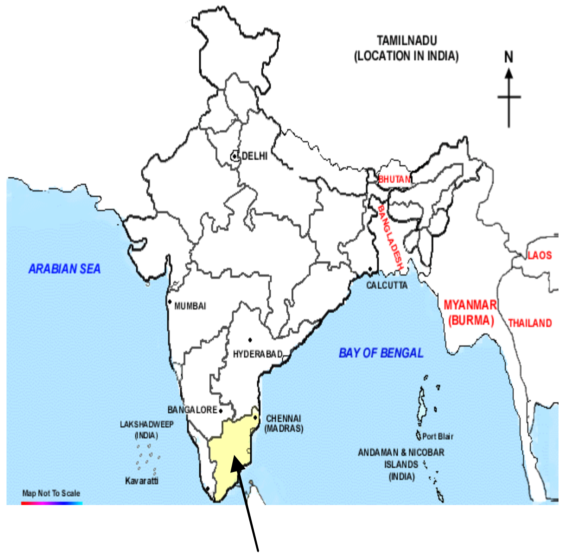
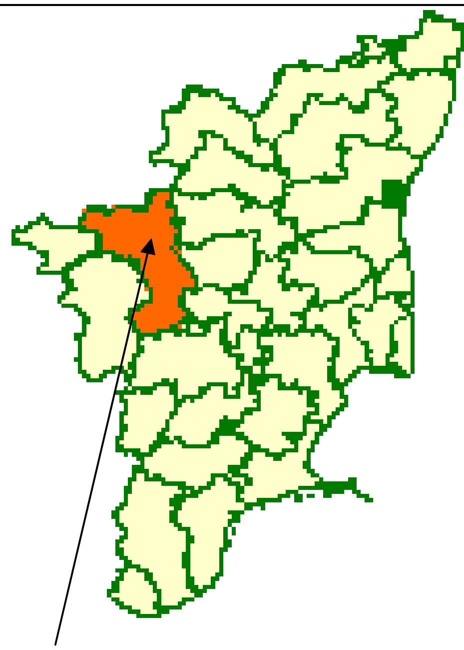
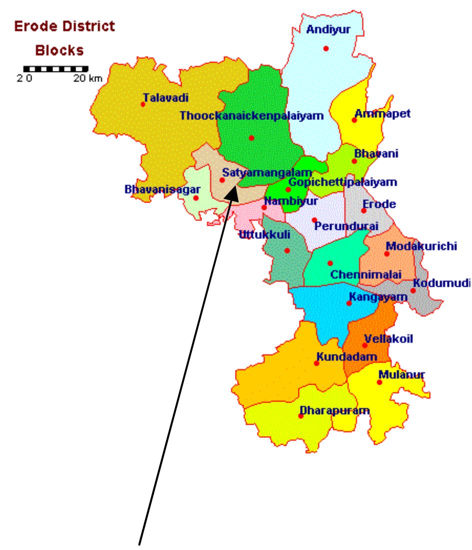
The 20 MW cogeneration plant is located at BASL's sugar factory at Alathukombai village of Sathyamangalam taluk, Erode District in the state of Tamil Nadu. The project activity is located at Latitude 11.3°N and Longitude 77.17°E. The nearest railway station is at Erode (around 45 kms) and the nearest airport at Coimbatore (around 60 kms). TNEB electrical sub-station for power export of 20 MVA is situated very near to this project, approximately two kilometres to where the surplus power is exported.



Tamil Nadu, India

 **Erode District, Tamil Nadu**	 **Sathyamangalam, Erode District**

A.4.2. Category(ies) of project activity:

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The project activity generates electricity from bagasse, which is a renewable fuel and therefore can be categorized under **"Category 1: Energy industries (renewable / non-renewable sources)"** as prescribed in the latest 'List of Sectoral Scopes' available at UNFCCC website.

A.4.3. Technology to be employed by the project activity:

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The project activity involves complete replacement of the existing low pressure biomass cogeneration system with a new high pressure system. The pre-project cogeneration plant consisted of two boilers (40 TPH and 30 TPH capacity) with parameters 32 kg/cm^2 and 380^0 Centigrade and two turbines of capacities 1.5MW and 3.0MW. These had significant operational lifetime left.

The cogeneration plant consists of a high pressure boiler; a suitable collaterally operating TG set and associated auxiliary equipment. The boiler is designed to generate 120 TPH steam at 87 ata pressure and 515ºC temperature using bagasse as the main fuel. The high pressure configuration has a better efficiency than the low pressure system, resulting in the generation of higher quantity of steam at a higher enthalpy for the same quantity of biomass input. The inlet feed water will be at 170 ºC with the feed water heated in high pressure feed water heaters. The TG set is rated for a nominal output of 20 MW with inlet steam parameters of 87 ata and 515ºC. The turbo-generator is of double extraction cum condensing type capable of operating during off-season when there is no process steam requirement. Surplus bagasse during season will be stored for operation in the off-season period.

The auxiliary plant systems include:

- Fuel (bagasse / biomass) handling system
- Ash handling system
- Cooling water system
- Raw water and de-mineralized (DM) water system
- Instrument air system, electrical system and EHV transmission system

The cogeneration plant is expected to generate a total power of 20 MW during season and off-season. After meeting steam and power requirements of sugar plant, cogeneration plant auxiliaries and BASL's adjacent granite factory, about 13.0 MW of surplus power during season and 17.5 MW during off-season would be exported to TNEB grid. The power generated in the TG set will be at 11 KV level, stepped down to 415V for feeding the plant equipments. Surplus power is stepped up to 110 KV for paralleling with the TNEB grid at the electrical sub-station, which is situated approximately two kilometres from the plant. Considering the overall electrical energy efficiency in the pre-project and project scenarios, the net quantity of increased electrical energy generation as a result of the project activity during the 10-year crediting period would be around 945 Million kWhs.

The high pressure configuration is more efficient, and therefore, the electricity generated from a certain quantity of biomass residue is higher than in the low pressure system; the average annual generation prior to the project activity was around 24.8 Million kWhs and increased to 119.1 Million kWhs after implementing the project activity. The incremental electricity generated is exported to the TNEB grid resulting in the displacement of an equivalent generation from other plants connected to the grid.

Since the project activity involves advanced cogeneration configuration, the Operation and Maintenance (O&M) personnel need to be trained for the proper operation of the plant. BASL has arranged to provide periodic training to its O&M personnel regarding the power plant and its control systems[3].

[3] Copies of proof of training are being submitted to the DOE

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

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Years	Annual estimation of emission reductions in tonnes of CO_2e
2011 - 2012	80,385
2012 - 2013	80,385
2013 – 2014	80,385
2014 - 2015	80,385
2015 - 2016	80,385
2016 - 2017	80,385
2017 - 2018	80,385
2018 - 2019	80,385
2019 - 2020	80,385
2020 - 2021	80,385
Total estimated reductions (tCO_2e)	803,850
Total number of crediting years	10
Average of estimated reductions over the crediting period (Tonnes of CO_2e)	**80,385**

A.4.5. Public funding of the project activity:

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No public funding is available for the 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 project activity:

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Title: Consolidated methodology for electricity generation from biomass residues (ACM0006)

Version 09

Reference: This consolidated baseline methodology (ACM0006) is based on elements from the following methodologies:

- AM0004: "Grid-connected Biomass Power-Generation that avoids uncontrolled burning of biomass which is based on the A.T Bio power Rice Husk Power Project in Thailand."
- AM0015: "Bagasse-based cogeneration connected to an electricity grid based on the proposal submitted by Vale do Rosario Bagasse Cogeneration, Brazil."
- NM0050: "Ratchasima SPP Expansion Project in Thailand."
- NM0081: "Trupan biomass cogeneration project in Chile."
- NM0098: "Nobrecel fossil to biomass fuel switch project in Brazil"

This methodology also refers to the following tools:

- ACM0002 ("Consolidated baseline methodology for grid-connected electricity generation from renewable sources")
- "Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site"
- "Combined tool to identify the baseline scenario and demonstrate additionality".
- "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion";
- "Tool to calculate baseline, project and/or leakage emissions from electricity consumption"

B.2. Justification of the choice of the methodology and why it is applicable to the project activity:

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The project activity generates electricity from the combustion of bagasse, a renewable biomass residue from the sugar mill, and feeds surplus electricity to the grid. All the applicability criteria of ACM0006 version 09 have been met by the project activity as described under:

Conditions of ACM0006	**Applicability to project activity**
Applicable to biomass residue fired electricity generation project activities	Bagasse fired in the project activity is a biomass residue.
Involves the improvement of energy efficiency of an existing power generation plant	The project involves the energy efficiency improvement of a power plant by replacing with a high efficiency power plant.
May be based on the operation of a power generation unit located in an agro-industrial plant generating the biomass residues	Based on the efficiency improvement of a power generation unit located in a sugar plant.
Biomass residues are defined as *biomass* that is a by-product, residue or waste stream from agriculture, forestry and related industries. This shall not include municipal waste or other wastes that contain fossilized and/or non-biodegradable material.	Bagasse used in the project activity is a residue from agriculture related industry (sugar plant).
No other biomass types than *biomass residues*, as defined above, are used in the project plant and these biomass residues are the predominant fuel used in the project plant (some fossil fuels may be co-fired).	Biomass residues will be used as the predominant fuel; however, some amount of coal may be co-fired during drought or other emergency situations.

For projects that use biomass residues from a production process (e.g. production of sugar or wood panel boards), the implementation of the project shall not result in an increase of the processing capacity of raw input (e.g. sugar, rice, logs, etc.) or in other substantial changes (e.g. product change) in this process.	During the conceptualization period of the project activity, the sugar plant was operating with a capacity of 4000 TCD and its energy requirements were met by the existing low efficiency cogeneration plant. There has been no further capacity expansion of the sugar plant during or after the project conceptualization period. The project activity uses the residue (bagasse) from sugar manufacturing. The production process is independent of the project activity and has not resulted in increase of the sugar plant crushing capacity. The sugar plant capacity was earlier expanded from 2500 TCD to 4000 TCD. However, this expansion has no link to the project activity. This was done much earlier during the year 1999[4], whereas the project activity was commenced only in March 2001.
The biomass used by the project facility should not be stored for more than one year.	Bagasse is not stored on the site for more than one year.
No significant energy quantities, except from transportation of the biomass, are required to prepare the biomass residues for fuel combustion	No preparation activity of biomass residues is done.
The methodology is only applicable for the 22 combinations of project activities and baseline scenarios identified in the methodology.	Project activity fits in scenario 14. Detailed description of applicability criteria for scenario 14 is given in Table B.2 in section B.5.

[4] This is evident from the extract from the Detailed Project Report and the purchase orders for the sugar mill expansion

B.3. Description of the sources and gases included in the project boundary:
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The spatial extent of the project boundary encompasses:

- The power plant at the project site
- The means for transportation of biomass residues to project site
- All power plants connected to the electricity grid

The spatial extent of the project boundary is depicted in the figure below:

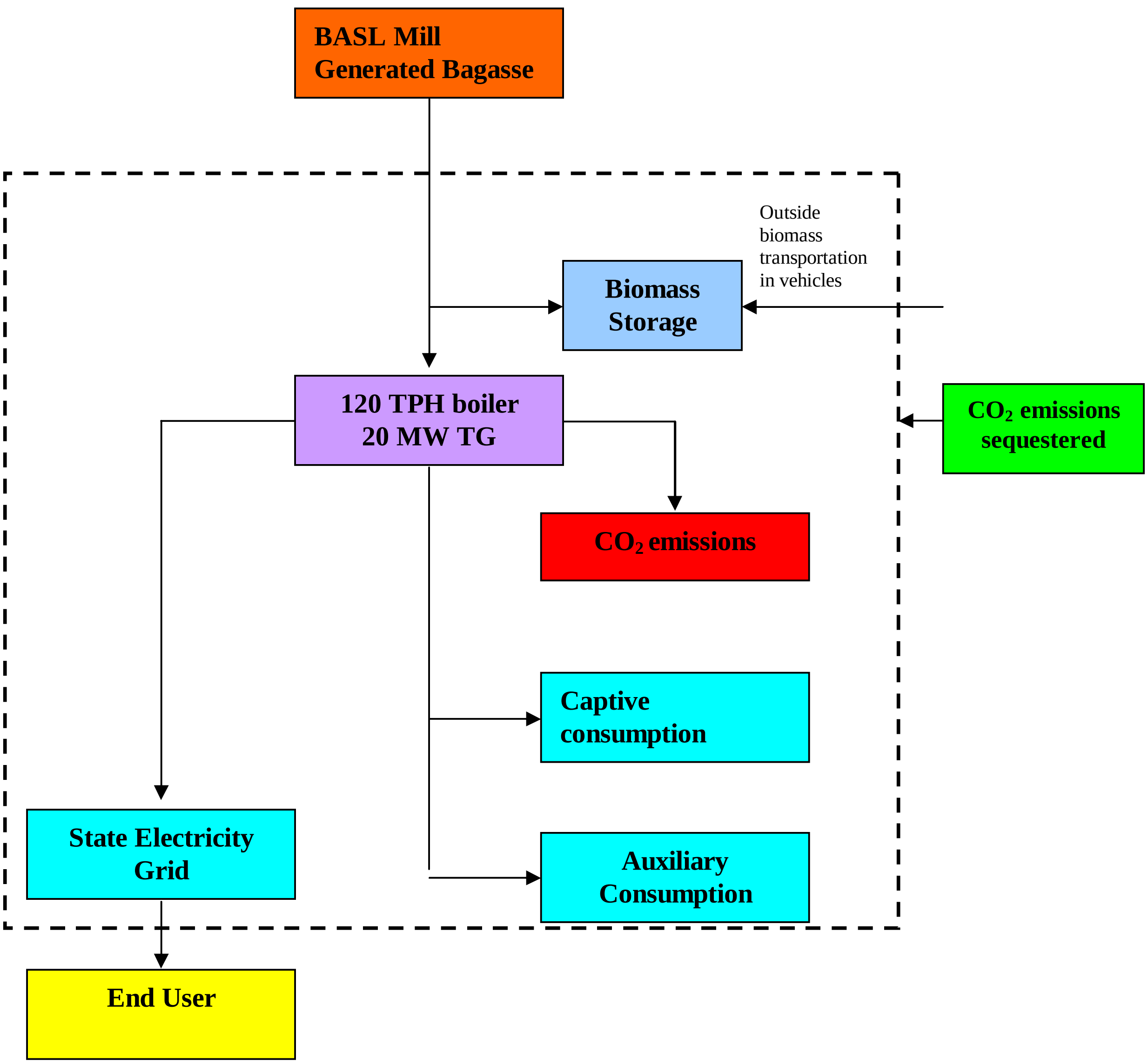

Figure B.1: Project boundary

Emission sources included in the project boundary:

The project participants have included in the project boundary, GHG emissions sources from the project activity and emission sources in the baseline, as prescribed by the methodology ACM0006.

The project boundary includes the following emission sources:

	Source	Gas		Justification/Explanation
Baseline Scenario	Electricity Generation	CO_2	Included	Main Emission source.
		CH_4	Excluded	Excluded for simplification. This is conservative.
		N_2O	Excluded	Excluded for simplification. This is conservative.
	Heat Generation	CO_2	Excluded	Main emission source
		CH_4	Excluded	Excluded for simplification. This is conservative.
		N_2O	Excluded	Excluded for simplification. This is conservative.
	Uncontrolled burning or decay of surplus biomass residues	CO_2	Excluded	No surplus biomass
		CH_4	Excluded	No surplus biomass
		N_2O	Excluded	Excluded for simplification. This is conservative.
Project Activity	Onsite fossil fuel and electricity consumption due to the project activity	CO_2	Included	Important emission source.
		CH_4	Excluded	Excluded for simplification. This quantity is very small.
		N_2O	Excluded	Excluded for simplification. This quantity is very small.
	Offsite transportation of biomass residues	CO_2	Included	An important emission source.
		CH_4	Excluded	Excluded for simplification. This quantity is very small.
		N_2O	Excluded	Excluded for simplification. This quantity is very small.

	Combustion of biomass residues for electricity and/or heat generation	CO_2	Excluded	It is assumed that CO_2 emissions from surplus biomass residues do not lead to changes of carbon pools in the LULUCF sector.
		CH_4	Excluded	This emission source must be included only if CH4 emissions from uncontrolled burning or decay of biomass residues in the baseline scenario are included.
		N_2O	Excluded	Excluded for simplification. This quantity is very small.
	Storage of Biomass residues	CO_2	Excluded	It is assumed that CO_2 emissions from surplus biomass residues do not lead to changes of carbon pools in the LULUCF sector.
		CH_4	Excluded	Excluded for simplification. Since biomass residues are stored for not longer than one year, this emission source is assumed to be small.
		N_2O	Excluded	Excluded for simplification. This quantity is very small.
	Waste water from the treatment of biomass residues.	CO_2	Excluded	Excluded. There is no waste water generated from the treatment of biomass residues. It is assumed that CO_2 emissions from surplus biomass residues do not lead to changes of the carbon pools in the LULUCF sector.
		CH_4	Excluded	Excluded. There is no waste water generated from the treatment of biomass residues.
		N_2O	Excluded	Excluded. There is no waste water generated from the treatment of biomass residues

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

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As prescribed by ACM0006 version 09, project participants have determined the baseline scenario and demonstrated additionality using the "Combined tool to identify the baseline scenario and demonstrate additionality" (version 02.2) shown in Figure B.2 below.

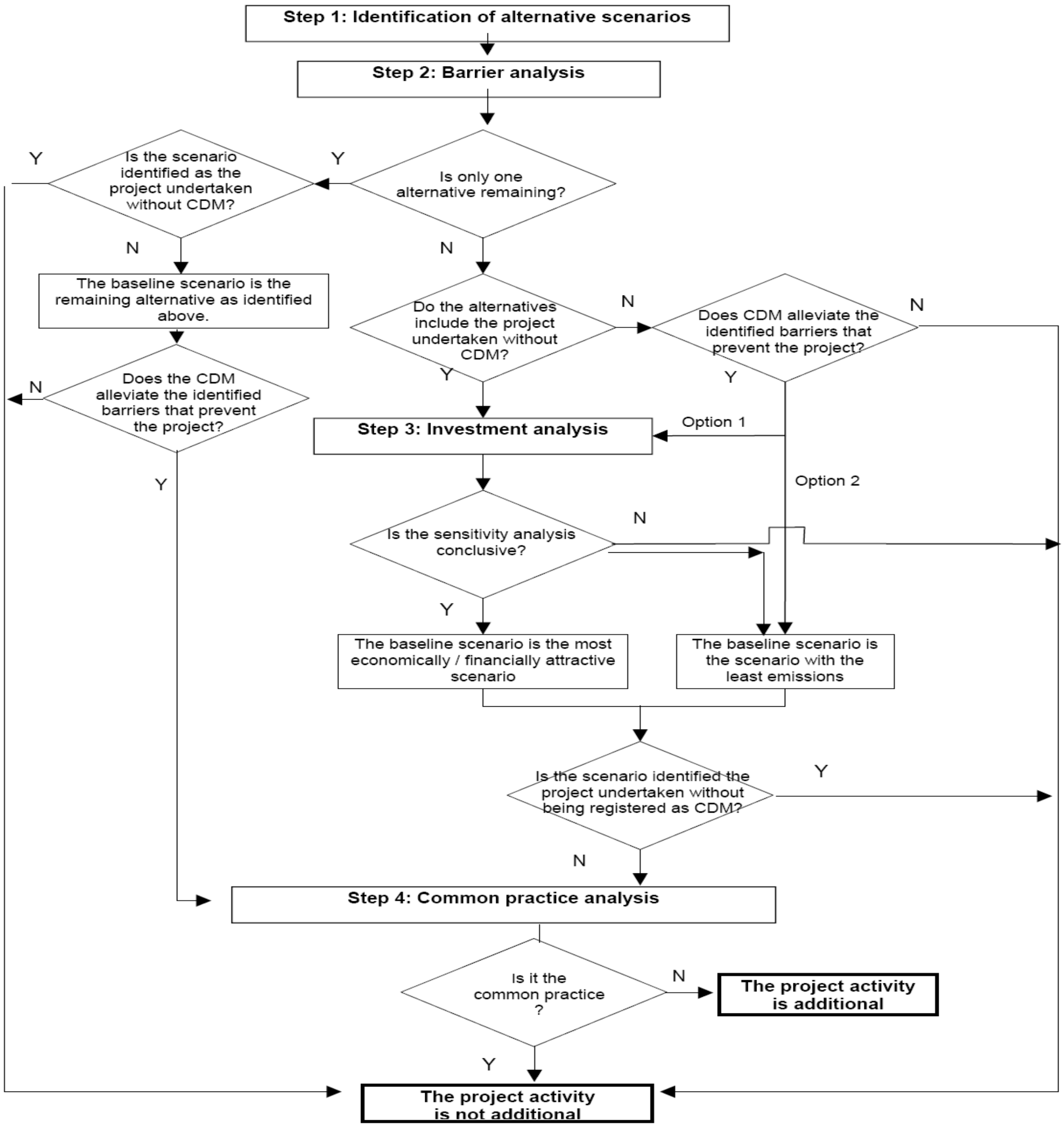

Figure B.2: Steps in the combined baseline and additionality tool

STEP. 1 Identification of alternative scenarios

This step serves to identify all alternative scenarios to the proposed CDM project activity(s) that can be the baseline scenario separately regarding:

a) How **power** would be generated in the absence of the CDM project activity

b) What would happen to the **biomass residues** in the absence of the project activity

c) In case of cogeneration projects: how the **heat** would be generated in the absence of the project activity

Step 1a. Define alternative scenarios to the proposed CDM project activity

IDENTIFICATION OF THE MOST PLAUSIBLE BASELINE SCENARIO

Requirements of the baseline cogeneration configuration:

The basic requirements of the "realistic and credible" baseline alternatives shall be that they should provide the same service as that of the project activity (i.e., the same steam and power quantity to meet the sugar plant captive requirements). The intention of identifying and describing the baseline scenario is to arrive at the most plausible alternative to the project activity that

- Is the economically most attractive technology
- Provides the same service (i.e the same heat quantity) as that of the project activity
- That is in compliance with relevant regulations

The project promoter was operating a 4000 TCD sugar plant with the existing low pressure system. The alternative scenarios would involve how BASL would have opted to deal with its power and steam requirements and the bagasse generated in the absence of the project activity. Considering the above aspects, the various alternatives available for BASL, as prescribed by ACM0006 are explored below;

Alternatives available for power generation:

P1 The proposed project activity not undertaken as a CDM project activity

This is a possible alternative scenario for the power generated in the project activity

P2 The continuation of power generation in an existing biomass residue fired power plant at the project site, in the same configuration, without retrofitting and fired with the same type of biomass residues as (co-)fired in the project activity

This is a possible alternative scenario for the power generated in the project activity. The existing cogeneration system at the site has sufficient capacity and life to continue operating. In this case, since the quantity of power generation would be smaller than the project plant, the incremental electricity generation would have been generated in the grid (Option P4).

P3 The generation of power in an existing captive power plant, using only fossil fuels
This is not an alternative to power generation since there is no fossil fuel based power plant at the site. Therefore, this alternative is not considered further.

P4 The generation of power in the grid
This is a possible alternative scenario for the power generated in the project plant. The entire quantity of power generated in the project activity or part of it could be generated in the grid. However, the option of 100% of power generation of project plant to be generated in the grid is not a credible option since captive cogeneration is an essential aspect in sugar mills for economical operation. However, the incremental power generation between the project plant and other power generation alternatives would be generated in the grid. Therefore option P4 will not be stand alone alternative, rather, it would be combined with other alternatives, in this case option P2.

P5 The installation of a **new** biomass residue fired power plant, fired with the same type and with the same annual amount of biomass residues as the project activity, but with a lower efficiency of electricity generation (e.g. an efficiency that is common practice in the relevant industry sector) than the project plant and therefore with a lower power output than in the project case.
This is a possible alternative to the power generated in the project activity. However, it may not be a credible alternative since the existing cogeneration plant itself is of an efficiency which is common practice in the sugar industry and has sufficient capacity and lifetime to continue operating. There is no necessity to install a new low efficiency plant when the existing plant can continue its operation at a similar efficiency. Therefore, this alternative is not considered further.

P6 The installation of a **new** biomass residue fired power plant that is fired with the same type but with a higher annual amount of biomass residues as the project activity and that has a lower efficiency of electricity generation (e.g. an efficiency that is common practice in the relevant industry sector) than the project activity. Therefore, the power output is the same as in the project case.

This is a possible alternative to the power generated in the project activity. However, it may not be a credible alternative since the existing cogeneration plant itself is of an efficiency which is common practice in the sugar industry and has sufficient capacity and lifetime to continue operating. There is no necessity to install a new low efficiency plant when the existing plant can continue its operation at a similar efficiency. Therefore, this alternative is not considered further.

P7 The **retrofitting** of an existing biomass residue fired power plant, fired with the same type and with the same annual amount of biomass residues as the project activity, but with a lower efficiency of electricity generation (e.g. an efficiency that is common practice in the relevant industry sector) than the project plant and therefore with a lower power output than in the project case.

This is a possible alternative to the power generated in the project activity. However, it may not be a credible alternative since the existing cogeneration plant itself is of an efficiency which is common practice in the sugar industry and has sufficient capacity and lifetime to continue operating. The existing system has sufficient capacity to fire the same annual amount of biomass residues as the project activity. Therefore, there is no necessity to retrofit the existing plant. Therefore, this alternative is not considered further.

P8 The **retrofitting** of an existing biomass residue fired power plant that is fired with the same type but with a higher annual amount of biomass residues as the project activity and that has a lower efficiency of electricity generation (e.g. an efficiency that is common practice in the relevant industry sector) than the project activity.

This is a possible alternative to the power generated in the project activity. However, it may not be a credible alternative since the existing cogeneration plant itself is of an efficiency which is *common practice in the sugar industry and has sufficient capacity and lifetime to continue operating. The existing system has sufficient capacity to fire the same annual amount of biomass residues as the project activity. Therefore, there is no necessity to retrofit the existing plant. Therefore, this alternative is not considered further.*

P9 The installation of a **new** fossil fuel fired captive power plant at the project site

This is a possible alternative for power generation. However this is not a credible alternative scenario. The primary business of BASL is sugar manufacturing. Bagasse cogeneration is an essential component of the sugar industry for its economical operation and is a common practice of sugar plants in India. It is not economical for sugar plants to install a captive fossil fuel power plant and combust high cost fossil fuels when the by-product bagasse is available. Therefore, this alternative is not considered further.

P10: The installation of a new single- (using only biomass residues) or co-fired (using a mix of biomass residues and fossil fuels) cogeneration plant with the same rated power capacity as the project activity power plant, but that is fired with a different type and/or quantity of fuels (biomass residues and/or fossil fuels). The annual amount of biomass residue used in the baseline scenario is lower than that used in the project activity;

Bagasse is a freely available by-product from sugar manufacturing. Bagasse based cogeneration, bagasse being the predominant fuel, is an essential aspect in Indian sugar mills for economical operation. It would be an economical option to use the freely available bagasse as the primary fuel for cogeneration rather than firing different type and/or quantity of fuels by purchasing at an additional cost. This alternative does not make business sense. Hence, this alternative is not a realistic and credible alternative.

P11: The generation of power in an existing fossil fuel fired cogeneration plant co-fired with biomass residues, at the project site.

There are no existing fossil fuel fired cogeneration plants at the project site. Hence, this alternative is not applicable.

Alternatives available for heat (process steam) generation:

H1 The proposed project activity not undertaken as a CDM project activity

This is a possible alterative to the heat generated in the project activity

H2 The proposed project activity (installation of a cogeneration power plant), fired with the same type of biomass residues but with a different efficiency of heat generation (e.g. an efficiency that is common practice in the relevant industry sector)

This is a possible alterative to the heat generated in the project activity. However, it may not be a credible alternative since the existing cogeneration plant itself is of an efficiency which is common practice in the sugar industry and has sufficient capacity and lifetime to continue operating. There is no necessity to install a new low efficiency plant when the existing plant can continue its operation at a similar efficiency. BASL would rather continue operating the existing plant than install a new plant of similar efficiency at high cost. Therefore, this alternative is not considered further.

H3 The generation of heat in an existing captive cogeneration plant, using only fossil fuels

This is a not a credible alterative to the heat generated in the project activity as there are no fossil fuel based captive cogeneration plant in the project site.

H4 The generation of heat in boilers using the same type of biomass residues

This is a possible alterative to the heat generated in the project activity. However, it is not a realistic alternative since cogeneration of heat and power is the established norm in sugar industries. Combustion of biomass residues in heat only boilers is an inefficient method compared to cogeneration and therefore cogeneration of power is an inherent and necessary component of any modern sugar mill from efficiency and economic point of view. Therefore, this alternative is not considered further.

H5 The continuation of heat generation in an existing biomass residue fired cogeneration plant at the project site, in the same configuration, without retrofitting and fired with the same type of biomass residues as in the project activity

This is a possible alterative to the heat generated in the project activity.

H6 The generation of heat in boilers using fossil fuels

This is a possible alterative to the heat generated in the project activity. However, it is not a realistic alternative since cogeneration of heat and power from biomass residues is the established norm in sugar industries. Combustion of fossil fuels in heat only boilers is an inefficient and uneconomic method compared to biomass cogeneration and therefore cogeneration of power is an inherent and necessary component of any modern sugar mill from efficiency and economic point of view. Therefore, this alternative is not considered further.

H7 The use of heat from external sources, such as district heat

This is a possible alterative to the heat generated in the project activity. However, it is not a realistic alternative since cogeneration of heat and power from biomass residues is the established norm in sugar industries. Use of heat from external sources is an uneconomic method compared to biomass cogeneration and therefore cogeneration of power is an inherent and necessary component of any modern sugar mill from efficiency and economic point of view. Therefore, this alternative is not considered further.

H8 Other heat generation technologies (e.g. heat pumps or solar energy)

This is a possible alternative to the heat generated in the project activity. However, it is not a realistic alternative since cogeneration of heat and power from biomass residues is the established norm in sugar industries. Heat generation from other technologies is an uneconomic method compared to biomass cogeneration and therefore cogeneration of power is an inherent and necessary component of any modern sugar mill from efficiency and economic point of view. Therefore, this alternative is not considered further.

H9: The installation of a **new** single- (using only biomass residues) or co-fired (using a mix of biomass residues and fossil fuels) cogeneration plant with the same rated power capacity as the project activity power plant, but that is fired with a different type and/or quantity of fuels (biomass residues and/or fossil fuels). The annual amount of biomass residue used in the baseline scenario is lower than that used in the project activity;

Bagasse is a freely available by-product from sugar manufacturing. Bagasse based cogeneration, bagasse being the predominant fuel, is an essential aspect in Indian sugar mills for economical operation. It would be an economical option to use the freely available bagasse as the primary fuel for cogeneration rather than firing different type and/or quantity of fuels by purchasing at an additional cost. This alternative does not make business sense. Hence, this alternative is not a realistic and credible alternative.

H10: The generation of power in an existing fossil fuel fired cogeneration plant co-fired with biomass residues, at the project site:

There are no existing fossil fuel fired cogeneration plants at the project site. Hence, this alternative is not applicable.

Alternatives available for biomass:

B1 The biomass residues are dumped or left to decay under mainly aerobic conditions. This applies, for example, to dumping and decay of biomass residues on fields.

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.

B2 The biomass residues are dumped or left to decay under clearly anaerobic conditions. This applies, for example, to deep landfills with more than 5 meters. This does not apply to biomass residues that are stock-piled or left to decay on fields.

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established *norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.*

B3 The biomass residues are burnt in an uncontrolled manner without utilizing it for energy purposes.

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.

B4 The biomass residues are used for heat and/or electricity generation at the project site

This is a possible alternative scenario for the biomass used in the project activity.

B5 The biomass residues are used for power generation, including cogeneration, in other existing or new grid-connected power plant

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.

B6 The biomass residues are used for heat generation in other existing or new boilers at other sites

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.

B7 The biomass residues are used for other energy purposes, such as the generation of biofuels

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case also) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.

B8 The biomass residues are used for non-energy purposes, e.g. as fertilizer or as feedstock in processes (e.g. in the pulp and paper industry)

This is a possible alternative scenario for the biomass used in the project activity. However, it may not be a realistic alternative since biomass residue fired cogeneration is an established norm in sugar mills from an efficiency and economic point of view. BASL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Only the surplus biomass residues (that are not used in the project activity case also) can be used for other purposes. BASL would not have any surplus bagasse after meeting energy requirements. Therefore, this alternative is not considered further.

List of plausible alternative scenarios to the project activity:

- ***Identified credible alternatives for power generation are P1, P2 & and P4.***

- ***Identified credible alternatives for heat generation are H1 and H5***
- ***Identified credible alternative for biomass residues is B4.***

Realistic and credible combinations of the alternatives for power, heat and biomass residues identified above are considered as plausible alternatives to the project activity and are listed below. These alternatives are in line with the combinations (scenarios) listed in ACM0006 version 09.

Outcome of step 1.a: List of plausible alternative scenarios to the project activity

The above combination of alternatives will result in the following realistic and credible alternatives to the project activity:

Alternative	Power generation	Heat generation	Biomass residues
BA 1	P1	H1	B4
BA 2	P2 and P4	H5	B4

Baseline Alternative 1 (BA1):

Combination of P1, H1 and B4.

- Implementation of the project activity not undertaken as a CDM project activity
- Installation of a high pressure cogeneration system
- The existing low pressure system would be de-commissioned
- The surplus power after meeting the captive requirements of the sugar mill would be exported to the grid

Under this alternative, BASL had the option to install a high pressure cogeneration system to replace the existing low pressure system without undertaking it as a CDM project activity. There was no restriction on BASL to export surplus power.

Baseline Alternative 2 (BA2):

Combination of P2, P4, H5 and B4.

The continuation of power and heat generation in the existing cogeneration plant using the same type and quantity of biomass residues as in the project activity and without any retrofits. Continuation of the existing low pressure cogeneration system and replacement with a high pressure cogeneration system at the end of its lifetime. BASL had the option to continue operating the low pressure system.

- The existing low pressure system had sufficient capacity to meet the captive power and steam requirements of the sugar plant. The steam and power balance is demonstrated in table T3.1 in annex 3.
- There would be no surplus power for export

Sub-step 1b: Consistency with mandatory laws and regulations:

Both the above two alternatives are consistent with applicable laws and regulations:

- The applicable regulations do not restrict BASL to continue steam and power generation using the lower efficiency pre-project system or in a high efficiency system
- The applicable regulations do not restrict BASL to continue steam and power generation from bagasse or other biomass.
- The applicable regulations do not restrict BASL the export or non-export of surplus power to the grid

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 CDM project activity (assessment and demonstration of additionality):

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ACM0006 version 09 prescribes the use of the “Combined tool to identify the baseline scenario and demonstrate additionality” (Figure B.2 in section B.4 above) for the above purpose, which is applied to the project activity. The step 1 of the tool is applied in section B.4 above and the subsequent steps are applied below:

The next step is to proceed with either Step 2 or Step 3. Step 2 (Barrier analysis) has been selected as the next step.

STEP 2 - BARRIER ANALYSIS

Sub-step 2a: Identification of barriers that would prevent the implementation of the project activity

BASL has implemented a high pressure cogeneration system to export power to the grid despite the barrier faced that is discussed in the subsequent section. The major barrier faced by BASL is as presented below:

§ **Prevailing Practice barrier:** The project activity technology is the first of its kind in the region.

The above barrier is further elaborated below:

Prevailing practice barrier:

The project activity is the first of its kind in the region. The Ministry of Non-Conventional Energy Sources (MNES) is the apex body in the country involved in the development and monitoring of renewable energy projects (including cogeneration) in the country[5]. MNES has appointed nodal agencies to represent it in each of the states. Tamil Nadu Energy Development Agency (TEDA) is the nodal agency for Tamil Nadu. The list of co-generation plants commissioned till date is published by TEDA[6]. Further, MNES has published the list of co-generation plants commissioned till year 2003. As indicated in the above sources, the list of cogeneration plants operating/planned at the time of investment decision of the project activity is below:

Table B.1

S.No	Name	Capacity	Commissioning date	Date of construction start[7]	Details
1	MRK Co-operative Sugar Mills Ltd	7.5	15.06.1992	Oct 1990	Co-operative sector. 43 ATA low pressure[8].

[5] http://mnes.nic.in/role.htm

[6] http://www.teda.gov.in/page/Bio-Ann19.htm

[7] This is arrived based on subtracting the gestation period for co-generation plants of 20 months, from the date of commissioning. The project activity was commissioned in 18 months (March 2001 to August 2002)

[8] http://www.avantgarde-india.com/services/showdetails.php?id=17

2	Cheyyar Co-operative Sugar Mills	7.5	18.03.1993	July 1991	Co-operative sector. 43 ATA low pressure[9].
3	Dharani Sugars & Chemicals Ltd	15	29.11.1996	Mar 1995	64 ATA pressure. Implemented under USAID Alternative Bagasse Co-gen (ABC) scheme[9].
4	Rajashree Sugars & Chemicals Ltd, Theni district	12	29.03.1996	July 1994	Low pressure, 43 ATA system[10]. Implemented with IREDA funding - ADB line of credit[11].
5	Kothari Sugars & Chemicals Ltd, Kattur, Trichy	12	24.12.1996	Apr 1995	67 ATA pressure. Implemented with ADB line of credit[12]
6	Thiru Arooran Sugars Ltd, Kotthumangudi – 609 403 A. Chittore, Vellore	18.68	06.05.1997	Sep 1995	67 ATA pressure. Implemented under USAID ABC scheme[10]
7	S.V. Sugar Mills Ltd	6	25.12.1997	Apr 1996	Low pressure system. Page 13 of their CDM PDD[13] states they have no prior experience in operating high pressure systems.
8	Subramania Siva Co-operative Mills Ltd	5	19.06.1998	Oct 1996	Co-operative sector. Low pressure[14].
9	Thiru Arooran Sugars,Thirumandangudi, Thanjavur District	28.42	13.11.1995	Mar 1994	64 ATA pressure. Refer page 9 of their PDD[15].
10	EID Parry India Ltd, Nellikuppam, Cuddalore dist	30	17.05.1997	Sep 1995	67 ATA pressure. Implemented under USAID ABC scheme[13].
11	Sakthi Sugar Mills,Sivagangai Unit	5.5	19.04.2002	Aug 2000	33 ATA pressure[9].

[9] http://www.renewingindia.org/newsletters/canecogen/current/Cane-15.pdf

[10] http://www.bee-india.nic.in/sidelinks/EC%20Award/Download/sugar/Rajshree%20Sugars%20and%20Chemicals%20Limited%20Varadaraj%20Nagar.pdf

[11] www.ireda.in/pdf/january-march_2006.pdf - refer page 19 of this link

[12] www.adb.org/documents/pcrs/ind/pcr_in8402.pdf - refer page 32 of this link

[13] http://cdm.unfccc.int/UserManagement/FileStorage/3MC84W74L94LSBAQ3UEC82IZ8FHJEY

[14] The first high pressure (67 ATA) system in a co-operative sugar mill was installed during 2003-04 in Maharashtra - http://mnes.nic.in/annualreport/2003_2004_English/ch5_pg8.htm

[15] http://cdm.unfccc.int/UserManagement/FileStorage/FS_808689329

12	Arunachalam Sugar Mills Ltd, Seomachipadi – 606 611	19	31.05.2002	Sep 2000	ADB funds received. Refer page 7 of ADB report[16]. 64.87[17] ATA pressure[18]
13	Bannari Amman Sugars Ltd, Sathyamangalam	20	26.08.2002	March 2001	**Project activity**
14	Auro Energy Ltd, Thanjavur district	16	23.12.2002	April 2001	Planned later than project activity
15	Supreme Renewable Energy Ltd at Sri Ambika Sugar Mills, Pennadam, Cuddalaore	40	21.03.2004	July 2002	Planned later than project activity
16	Sakthi Sugar Mills Pvt. Ltd, Erode	32	15.11.2003	Mar 2002	Planned later than project activity
17	Rajashree Sugars Chemicals Ltd., Munchiambakkam, Villupuram	22	01.06.2005	Oct 2003	Planned later than project activity
18	EID Parry India Ltd., Pudukottai	18	30.03.2006	July 2004	Planned later than project activity
19	Kothari sugars and Chemicals Ltd., Ariyalur, Perambalur District	22	31.03.2007	July 2005	Planned later than project activity

It may be noted from Table B.1 above that there were no plants with 87 ATA high pressure technology operating/planned in the state of Tamil Nadu, during conceptualization of this project activity (in March 2001). The project activity was the first of its kind in the region. *It is clearly established that during the conceptualization of the project activity (in March 2001), the high pressure technology, especially the 87 ATA, was first of its kind in the region. Few of the plants installed with 67 ATA technology were also implemented under special financial schemes as described.*

Though it is not appropriate to consider a country wise analysis as the regulatory framework/scenario and investment climate in India is different from state to state, the status of 87 ATA high pressure technology operating/planned in India is also being analyzed as given below:

[16] http://www.adb.org/Documents/PCRs/IND/pcr-ind-27068.pdf

[17] The rated working pressure of the boiler is 66 kg/cm^2(g) = ((66 X 0.967841) + 1) ATA= 64.87 ATA (Ab)

[18] Letter from Avant-Garde on boiler specification of Arunachalam Sugar Mills Limited

As per MNES annual report of the year 2002-03, the country's first 87 ATA sugar cogeneration plant was installed during the year 2002-03 (in Kakatiya Sugars, Andhra Pradesh)[19]. In the same report, the completion period is stated as 18 months. The sugar cogeneration plant at Kakatiya Sugars was commissioned on 12/04/2002[20]. Considering the completion period of 18 months, the construction start of this plant would have been in November 2000, and it gives an indication that conceptualization[21] of the sugar cogeneration project by BASL Satyamangalam had been taken parallely during the same time. The MNES annual report of year 2002-03 also indicates that 87 ATA were commissioned during the year in the states of Andhra Pradesh (Kakatiya Sugars- May 2002) and Tamil Nadu (Project activity – commissioned in August 2002)[22].

From the information available from MNES, it can be stated that

- ***there were no plants in operation with 87 ATA sugar cogeneration plant in the country during the time of conceptualization of the project activity***

Outcome of step 2-a: The barrier that may prevent one or more alternative scenarios to occur is as follows:

The barrier that may prevent the alternative scenarios to occur is the prevailing practice barrier (First of its kind)

Sub-step 2b. Eliminate alternative scenarios which are prevented by the identified barriers:

Baseline alternative 1 (BA1):

The prevailing practice is applicable to this alternative and could prohibit the implementation of the project activity not undertaken as a CDM project activity.

[19] http://mnes.nic.in/annualreport/2002_2003_English/ch5_pg14.htm - (Page No. 14 of Chapter 5 of the Annual report 2002-2003) - Implemented with IREDA funding under ADB line of credit

[20] http://www.nedcap.gov.in/biomassincentives.aspx

http://cdm.unfccc.int/UserManagement/FileStorage/WNEORK0SAHCT9425JDI8VLPQ1U3B6Y

http://cdm.unfccc.int/Projects/DB/SGS-UKL1200599187.35/ReviewInitialComments/T8SY9UG1IAVRCEJKU43LRHY5F2PZJG (MNES data refers to a date of commissioning of Kakatiya Sugars in May 2002)

[21] Discussions with technical consultant and CII on the technical and financial feasibility of the 20 MW Cogeneration project, concept of CDM and its applicability to cogeneration projects

[22] http://mnes.nic.in/annualreport/2002_2003_English/ch5_pg11.htm - (Page No. 11 of Chapter 5 of the Annual report 2002-2003)

Baseline alternative 2 (BA2):

The low pressure technology is a common practice in Indian sugar industry and BASL has the necessary expertise, skilled manpower and other resources to operate the plant without any significant risks associated with the 87-ata system. The continuation of the low pressure system would not require capacity building or training exercise as required by the project activity.

Outcome of Step 2b: List of alternative scenarios to the project activity that are not prevented by any barrier. The list of baseline alternative after Step 2 "Barrier analysis" are:

Baseline Alternative 2 (BA2):

Combination of P2, P4, H5 and B4.

The continuation of power and heat generation in the existing cogeneration plant using the same type of biomass residues as in the project activity and without any retrofits.

- Continuation of the existing low pressure cogeneration system and replacement with a high pressure cogeneration system at the end of its lifetime. BASL had the option to continue operating the low pressure system.
- The existing low pressure system had sufficient capacity to meet the captive power and steam requirements of the sugar plant
- There would be no surplus power for export

Since only one alternative remains, this is considered as the most plausible baseline scenario for the project activity. This alternative corresponds to scenario 14 of ACM0006 version 09. The description of scenario 14 as per ACM0006 version 09 and justification of how this baseline alternative falls under this scenario is provided in Table B.2 below:

Scenario 14 criteria	***Applicability to project***
The project activity involves the improvement of energy efficiency of an existing biomass residue fired power plant by retrofit or replacement of the existing biomass residue fired power plant at a site where no other power plants are operated.	The project involves the improvement of energy efficiency of the existing low pressure 4.5 MW bagasse based cogeneration plant with a new 20 MW high efficiency high pressure cogeneration system. There are no other power plants operated at the site.

The retrofit or replacement increases the power generation capacity, while the thermal firing capacity is maintained.	The replacement increases the power generation capacity from 4.5 MW to 20 MW. The thermal firing (bagasse firing) capacity of the project plant (50 TPH) is same as that of the pre-project plant (50 TPH) as confirmed in the Chartered Engineer certificate.
In the absence of the project activity, the existing power plant would continue to operate without significant changes. The same type and quantity of biomass residues as in the project plant would in the absence of the project activity be used in the existing plant.	In the absence of the project activity, the existing 4.5 MW low pressure system would continue to operate without any significant changes as elaborated in the table T3.1 in annex 3. The existing cogeneration plant was inspected by Chartered Engineer to assess its remaining useful lifetime. As per the assessment[23], the lifetime of the plant was expected to be till year 2020. This is within the crediting period of the project activity. The existing plant was meeting the energy requirements of the 4000 TCD sugar plant and would have continued operating without any significant changes. In the absence of the project activity, the existing plant would use the same quantity of bagasse as in the project plant to cater the captive energy requirements. (Refer annex 3 Table T3.1)
Consequently, the power generated by the project plant would in the absence of the project activity be generated (a) in the same plant (without project implementation) and – since power generation is	The power generated in the project plant (20 MW) would in the absence of the project activity be generated (a) in the existing 4.5 MW system and (b) the remaining in the grid.

[23] Life assessment certificates submitted to the DOE.

larger due to the energy efficiency improvements – (b) partly in power plants in the grid.	
In case of cogeneration plants, the heat generated by the project plant would in the absence of the project activity be generated in the same plant. The efficiency of heat generation i.e. heat generated per biomass input is smaller or the same after the implementation of the project activity.	In the absence of the project activity, the heat generated by the project plant would be generated in the existing (pre-project) plant. The project plant generates 66.67 TPH of 2.5 ata steam and 3.33 TPH of 8 ata steam. This would have been generated by the existing 4.5 MW system in the absence of the project activity. The efficiency of heat generation of the project plant is higher (0.72 MWhth/MWhbiomass) than that of the pre-project system (0.67 MWhth/MWhbiomass).

Thus, the project activity clearly falls under scenario 14 of ACM0006 version 09.

The next step as per Figure B.2 is Step 4: Common practice analysis

STEP 4 - COMMON PRACTICE ANALYSIS

Sub-step (4a): Analyse other activities similar to the project activity

Similar plants include those cogeneration plants that are of similar technical configuration (like pressure) and those which operate in a similar policy/regulatory framework (like power purchase tariff).

Similar projects: For the project activity, similar plants are those with a pressure of 87 ATA

Project Region: Tamil Nadu is the appropriate region for the project activity. This is because power purchase tariff and policies and investment climate are different from state to state. The choice of this project region is appropriate as per the "combined tool to identify the baseline scenario and demonstrate additionality (Version 02.2)"

The above referred combined tool which states that *"Similar activities are defined as activities (i.e. technologies or practices) that are of similar scale, take place in a comparable environment, inter alia, with respect to the regulatory framework and are undertaken in the relevant geographical area…."*

The list of cogeneration plants operating/planned in Tamil Nadu at the time of the investment decision is given in Table B.1 above. As described under "Barrier analysis" above, there were no cogeneration plants with 87 ATA high pressure system in the region.

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

The analysis in sub-step 4a above shows that similar project activities are not widely observed and not commonly carried out in the region and that the project activity is the first of its kind in the region. Therefore it may be stated that the project activity is not a common practice.

List of cogeneration plants operated/planned by BASL at other locations during the time of investment decision:

BASL was operating a 67 ATA cogeneration system at its sugar plant at Nanjangud, Karnataka state, which was commissioned during year 2000. Inspired by the 67 ATA systems installed under the USAID-ABC scheme in the region, BASL had also installed a 67 ATA system at our Karnataka state sugar factory in the year 2000. However, since commissioning, BASL faced several recurring operational problems in its operation. The major problems faced were - Scaling of Turbine internals, load hunting, high gear box vibrations, boiler tubes erosion and furnace puffing. The turbine had to be overhauled for rectification which caused a generation loss of 10% for the year amounting to INR 20.4 Million. This showed that the high pressure technology was still in its infancy and is yet to be established in the region, which left a negative impact on our management. The scaling of turbines was attributed to the insufficient experience of the personnel in monitoring and control of water quality. Further, this 67 ATA plant is located in Karnataka where the power tariff and investment climate are different from Tamil Nadu. No other cogeneration plants were being planned or constructed by BASL at the time of investment decision.

Since all the criteria of the "Combined tool to identify the baseline scenario and demonstrate additionality***" are satisfied, the project may be considered additional.***

Serious CDM Consideration: ***Awareness of CDM prior to project decision making:***

The below sequence of events substantiates the fact that BASL was aware of the CDM before their decision to implement the project activity and had seriously considered the CDM as a factor while decision making. (Relevant supporting documents submitted to DOE).

Date	**Event**
14th March 2000	BASL receives letter from the Confederation of Indian Industries (CII) indicating the potential of CDM benefits for high pressure cogeneration projects. An application form for availing CDM benefits under USAID is enclosed by CII.
20th April 2000	BASL submits the completed CII application form for availing CDM benefits.
05th June 2000	Letter from CII acknowledging BASL on the CDM application form submitted. CII further states that "the CDM modalities at the international level are under negotiation and finalization". No further response received from CII.
30th August 2000	The cogeneration plant engineering consultant ("Avant-Garde Engineers and Consultants Pvt. Ltd") provides further details to BASL about the concept of CDM and its applicability to cogeneration projects. They also provide some newsletters on CDM to BASL along with their letter.
20th September 2000	The Board of Directors decide to implement the high efficiency project considering the prospect of CDM funds ("Minutes of meeting")
October 2000	Detailed Project Report (DPR) is prepared by the cogeneration plant engineering consultant, in which the consideration of CDM is incorporated (extract from DPR)

01st December 2000	With the objective of taking the project forward in the CDM process, BASL's representative attended a seminar on carbon trading[24], organized by CII[25], USAID and WII.
05th March 2001	**Purchase orders were placed for the project equipments.**

Serious CDM Consideration: ***Continuing efforts to secure CDM status:***

BASL had initiated efforts to secure CDM status for this project even before the project start date and continued to make such efforts in parallel with the project implementation. Their efforts to secure CDM status were stalled due to the absence of a proper institutional framework during years 2001-02 and due to which they were able to formally commence the CDM cycle only in March 2003. The below sequence of events substantiates the same. (Relevant supporting documents submitted to DOE).

Date	Event
05th March 2001	**Purchase orders were placed for the project equipments.**
24th May 2001	BASL meets a CDM Consultant (Price Waterhouse Coopers) regarding the procedures to avail CDM benefits for their project along with their funding agency (ICICI Bank). The CDM consultant informs that the project can be developed only after the technical aspects of CDM were finalized by the UNFCCC, which are presently under negotiation. ("Minutes of meeting").
10th July 2001	Letter to BASL from USAID's "GHG Prevention Project – Climate Change Supplement (GEP-CCS)" stating that they would facilitate international funding for clean energy projects. They also inform that "International financing mechanisms for clean energy projects that mitigate climate change are yet to take firm shape".
20th July 2001	BASL submits the required details to GEP-CCS requesting them to

[24] Seminar invitation and delegate pass submitted to DOE

[25] CII – Confederation of Indian Industries, USAID – United States Agency for International Development, WII – Winrock International India

	arrange for carbon benefits to their cogeneration project.
23rd July 2001	E-mail from Mr. Vinay Deodhar[26], GEP-CCS requesting for additional details about the project. Further, they inform BASL that "the negotiations under UNFCCC are not likely to result in viable market development mechanisms like CDM in near future".
27th August 2001	BASL submits additional project details to GEP-CCS and awaits their feedback. However, no further progress was made through GEP-CCS until August 2002, when they re-established contact.
November 2001	"The Marrakesh Accords" defining the modalities and procedures of CDM is published by the UNFCCC.
29th April 2002	BASL meets representative of Rabobank India regarding carbon credits for their biomass based projects.
15th May 2002	Circular from Indian Sugar Mills Association (ISMA) informing about carbon trading opportunities for sugar industry, requesting interested parties to write to Winrock International India (WII), New Delhi, for providing the necessary guidelines.
08th June 2002	BASL initiates dialogues with WII regarding the formalities required for the CDM approval of their cogeneration project activity.
18th June 2002	E-mail from WII to BASL expressing their intention to help BASL avail CERs and requests some technical and financial details about the project.
8th July 2002	BASL submits the required technical and financial details to WII.
02nd August 2002	WII submits their proposal for assisting BASL in the CDM process.
22nd August 2002	BASL requests WII for further clarification regarding the CDM process and their experience in the sector.
29th August 2002	WII reverts back to BASL providing clarifications and their previous experience in the sector.
20th August 2002	Meanwhile, GEP-CCS re-establishes contact with BASL regarding the requirement of carbon offsets by an international emissions broker and

[26] Presently, member of the CDM Registration and Issuance Team of the UNFCCC

	requests for some project details.
23rd August 2002	BASL provides the necessary project details to GEP-CCS. However, no further progress is made through GEP-CCS.
26th August 2002	Date of commissioning of the project activity
30 August 2002	BASL contacts ICICI bank regarding availing carbon credits. Representative of ICICI bank visits BASL. Refer e-mail dated 30.08.2002 from ICICI Bank, Mumbai to BASL. No response is received from ICICI. BASL sends a reminder e-mail on 02nd December 2002.
22nd November 2002	WII re-establishes contact with BASL regarding the purchase of emission reductions by one of their clients and seeks the present status of their project.
02nd December 2002	BASL submits the required project status details to WII. However, no further progress is made through WII.
16th November 2002	BASL gets in touch with their present CDM consultant (E & Y Pvt Ltd) during the seminar "Enviro 2002" conducted by CII on 15th to 16th November 2002 at Chennai, Tamil Nadu. Further discussions on GHG emission trading are done on 19th November 2002.
December 2002	Discussions continue between BASL and the consultant (E & Y Pvt Ltd).
January 2003	CDM consultant (E & Y Pvt Ltd) submits a proposal to assist BASL in availing the carbon credits.
21st March 2003	After negotiations, the CDM consultant (E & Y Pvt Ltd) is appointed by BASL
17th September 2003	Project Idea Note submitted to IFC-Netherlands Carbon Facility
14th October 2003	Enquiries with DOEs for validation
7th November 2003	Proposal received from DOEs

December 2003	DOE appointed for Validation. Refer work order receipt letter from DOE. However, validation could not be commenced due to absence of suitable methodology. The consultant had applied for a new bagasse co-generation methodology[27] for a similar project activity and BASL was awaiting its approval.
January 2004	PDD was submitted to DNA for approval.
May 2004	Host Country Approval was obtained[28].
August 2004	Dialogues with carbon buyer Rabo Bank for Emission Reduction Purchase Agreement (ERPA). Several correspondences continue till year 2006.
28th Feb 2005	Revised HCA obtained as per the DNA's new format
April 2006	Validation was commenced using ACM0006 version 02. Till such time, a suitable CDM methodology was not available.
May 2007	PDD re-webhosted for Validation using ACM0006 version 04.
January 2008	Request for Registration submitted
August 2008	Project activity withdrawn by DOE
26th November 2008	Project activity webhosted for Validation using ACM0006 version 06.2

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

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The emission reductions are mainly from the incremental energy generation using the same quantity of biomass that would have been combusted in the baseline scenario (low pressure cogeneration plant). The incremental energy is exported to the grid and displaces equivalent CO_2 emission from grid connected power plants. This section elaborates on the formula used to calculate the project emissions, baseline emissions, leakage and net emission reductions based on ACM0006 version 09.

[27] NM0030 was submitted for the bagasse co-generation project activity implemented by Balrampur Chinni Mills Limited, which was also worked by our CDM consultant.

[28] This was later renewed as per the latest host country approval format

As defined in section B.4 and B.5 above, the baseline alternative 2 is the most likely baseline scenario which is a combination of options P2, P4, H5 and B4. This corresponds to scenario 14 of ACM0006 version 09 and therefore, for this project activity, the formula applicable to baseline scenario 14 would be used.

B.6.1.1 Emission Reductions (ER_y)

The project activity mainly reduces CO_2 emissions through substitution of power and heat generation using both biomass and fossil fuels by energy generation with only biomass residues. The emission reduction ERy by the project activity during a given year y is the difference between the emission reductions through substitution of electricity generation with fossil fuels ($ER_{electricity,y}$), the emission reductions through substitution of heat generation with fossil fuels ($ER_{heat,y}$), project emissions (PE_y), emissions due to leakage (L_y) and, where this emission source is included in the project boundary and relevant, baseline emissions due to the natural decay or burning of anthropogenic sources of biomass residues ($BE_{biomass,y}$), as follows:

$ER_y = ER_{heat,\,y} + ER_{electricity,\,y} + BE_{biomass,\,y} \bullet PE_y \bullet L_y$

Where:

ER_y = Emissions reductions of the project activity during the year y (tCO2/yr)

$ER_{electricity,y}$ = Emission reductions due to displacement of electricity during the year y (tCO2/yr)

$ER_{heat,y}$ = Emission reductions due to displacement of heat during the year y (tCO2/yr)

$BE_{biomass,y}$ = Baseline emissions due to natural decay or burning of anthropogenic sources of biomass residues during the year y (tCO2e/yr)

PE_y = Project emissions during the year y (tCO2/yr)

L_y = Leakage emissions during the year y (tCO2/yr)

B.6.1.2 Project emissions (PE_y)

Project emissions include:

- CO2 emissions from transportation of biomass residues to the project site (PET_y),
- CO2 emissions from on-site consumption of fossil fuels due to the project activity ($PEFF_y$),

- CO2 emissions from consumption of electricity ($PE_{EC,y}$),
- Where this emission source is included in the project boundary and relevant: CH4 emissions from the combustion of biomass residues ($PE_{Biomass,CH4,y}$),
- Where waste water from the treatment of biomass residues degrades under anaerobic conditions: CH4 emissions from waste water.

Project emissions are calculated as follows:

$PE_y = PET_y + PEFF_y + PE_{EC,y} + GWP_{CH4} . (PE_{Biomass,CH4,y} + PE_{WW,CH4,y})$

Where:

PET_y	CO_2 emissions during the year y due to transportation of the biomass residues to the project plant (tCO_2/yr)
$PEFF_y$	CO_2 emissions during the year y due to fossil fuels co-fired by the generation facility or other fossil fuel consumption at the project site that is attributable to the project activity (tCO_2/yr)
$PE_{EC,y}$	CO_2 emissions during the year y due to electricity consumption at the project site that is attributable to the project activity (tCO_2/yr)
GWP_{CH4}	Global Warming Potential for methane valid for the relevant commitment period
$PE_{Biomass,CH4,y}$	CH_4 emissions from the combustion of biomass residues during the year y (tCH_4/yr). These emissions are not applicable since this is not included in the project boundary.
$PE_{ww,CH4,y}$	CH_4 emissions from the waste water generated from treatment of biomass residues during the year y (tCH_4/yr). There is no treatment of biomass residues or waste water generation from biomass treatment involved in the project activity. Hence there is no CH_4 emissions from waste water generated from the treatment of biomass residues.

B.6.1.2.1 Carbon dioxide emissions from combustion of fossil fuels for transportation of biomass residues to the project plant (*PETy*):

Out of the two different approaches provided in ACM0006 version 09, option 1 has been selected for the calculation of this source of project emissions.

$$PET_y = N_y \times AVD_y \times EF_{Km,CO_2}$$

Where:

N_y	Number of truck trips during the year *y*
AVDy	is the average return trip distance between the biomass fuel supply sites and the site of the project plant in kilometers (km) during the year y and
$EF_{km,CO2}$	is the average CO2 emission factor for the trucks measured during the year y in tCO2/km

B.6.1.2.2 Carbon dioxide emissions from on-site consumption of fossil fuels (*$PEFF_y$*)

The proper and efficient operation of the biomass residue fired power plant may require using some fossil fuels, e.g. for start-ups or during rainy season (when the moisture content in biomass residue is too high) or for the preparation or on-site transportation of the biomass residues. In addition, any other fuel consumption at the project site that is attributable to the project activity should be taken into account (e.g. for mechanical preparation of the biomass residues).

CO_2 emissions from on-site combustion of fossil fuels ($PEFF_y$) has been calculated using the latest approved version (02) of the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion". CO_2 emissions from combustion of respective fossil fuels are calculated as follows:

$$PEFF_y = \sum_i FC_{i,j,y}\ x\ COEF_{i,y}$$

where,

$PEFF_y$ is the project emission from fossil fuel co-firing during the year y in tons of CO_2,

$FC_{i,j,y}$ is the quantity of fuel type i combusted in process j during the year y. As per ACM0006, the processes "j" are; Fossil fuels combusted in the project plant during the year y ($FF_{project\ plant,i,y}$) and Fossil fuels combusted at the project site for other purposes that are attributable to the project activity during year y ($FF_{project\ site,i,y}$). Fossil fuel combustion in standby DG sets during start-up or maintenance activities and in fuel feeding vehicles would not be part of this parameter. Only that fossil fuel consumption attributable to the energy efficiency improvement would be included in this parameter.

$COEF_{i,y}$ Is the CO_2 emission coefficient of fuel type *i* in year *y* (tCO_2/mass or volume unit). Out of the two options provided in the tool for calculating this parameter, option B is applied for this project activity as follows:

Option B: The CO_2 emission coefficient $COEF_{i,y}$ is calculated based on net calorific value and CO_2 emission factor of the fuel type *i*, as follows:

$$COEF_{i,y} = NCV_i \, x \, EF_{CO2,i,y}$$

$EF_{CO2,i,y}$ is the weighted average CO_2 emission factor of the fossil fuel type 'i' in tCO_2/GJ in a year y.

NCV_i is the weighted average calorific value of the fossil fuel type 'i' in GJ per mass unit in year y.

Consolidating the above sub-equations, the main equation may be elaborated as follows:

$$PEFF_y = \sum_i \left(FF_{project\ plant,i,y} + FF_{project\ site,i,y} \right) x \ NCV_{i,y} \ x \ EF_{CO_2,i,y}$$

B.6.1.2.3 Carbon dioxide emissions from electricity consumption (*$PE_{EC,y}$*)

Any electricity consumption at the project site attributable to the project activity, excluding that of the power plant auxiliary[29] equipments, would be part of this parameter. However, any additional electricity consumption due to the project activity from other sources would be calculated using the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" as follows:

$$PE_{EC,y} = \sum_J EC_{PJ,j,y} x EF_{EL,j,y} x (1 + TDL_{j,y})$$

Where,

$PE_{EC,y}$ = Project emissions from electricity consumption in year y (tCO_2/yr)

[29] Auxiliary consumption would be deducted from gross energy generation. Only the net generation is considered in calculating baseline emissions.

$EC_{PJ,j,y}$ = Quantity of electricity consumed by the project electricity consumption source j in year y (MWh/yr).

$EF_{EL,j,y}$ = Emission factor for electricity generation for source j in year y (tCO_2/MWh). The default value of 1.3 tCO_2/MWh is chosen and will be applied in calculating any electricity consumption at the project site attributable to the project activity

$TDL_{j,y}$ = Average technical transmission and distribution losses for providing electricity source j in year y. Default value of 20% will be applied.

Determination of the emission factor for electricity generation ($EF_{EL,j,y}$):

As per the tool, the following three scenarios may apply for the source of electricity consumption.

Scenario A: Electricity consumption from grid

This is applicable. Some amount of electricity may be imported during emergencies to operate the project plant auxiliaries.

Scenario B: Electricity consumption from (an) off-grid fossil fuel fired captive power plant(s)

Not applicable. The electricity consumption from the use of captive DG power during project plant maintenance would not be covered under this parameter since this would anyways occur in the absence of the project activity also. This is expected to be zero.

Scenario C: Electricity consumption from the grid and (a) fossil fuel fired captive power plant(s)

Not applicable due to the same reason as stated under scenario B above.

B.6.1.2.4 Methane emissions from combustion of biomass residues ($PE_{Biomass,CH4,y}$)

These emissions are not included in the project boundary and are neglected both in project missions and baseline emissions.

B.6.1.2.5 Methane emissions from waste water treatment ($PE_{WW,CH4,y}$)

There is no waste water generation from the preparation of biomass residues. Therefore, this parameter is equal to zero.

As described above, the project emissions equation reduces to:

$PE_y = PET_y + PEFF_y + PE_{EC,y}$

B.6.1.3 Emission reductions due to displacement of electricity:

Emission reductions due to the displacement of electricity is calculated by multiplying the net quantity of increased electricity generated with biomass residues as a result of the project activity (EG_y) with the CO_2 baseline emission factor for the electricity displaced due to the project ($EF_{electricity,y}$), as follows:

$$ER_{electricity,y} = EG_y \cdot EF_{electricity,y}$$

Where:

$ER_{electricity,y}$	Emission reductions due to displacement of electricity during the year *y* (tCO_2/yr)
EG_y	Net quantity of increased electricity generation as a result of the project activity (incremental to baseline generation) during the year *y* (MWh)
$EF_{electricity,y}$	CO_2 emission factor for the electricity displaced due to the project activity during the year *y* (tCO_2/MWh)

B.6.1.3.1 Determination of $EF_{electricity,y}$:

The determination of the emission factor for displacement of electricity $EF_{electricity,y}$, depends of the baseline scenario identified. The project activity displaces electricity from other grid-connected sources or from less efficient plants fired with the same type of biomass residue. Apart from co-firing fossil fuels in the project plant, where relevant, electricity is not generated with fossil fuels in the project site. The emission factor for the displacement of electricity should correspond to the grid emission factor ($EF_{electricity,y} = EF_{grid,y}$). ACM0006 version 09, recommends that if the power generation capacity of the biomass power plant is more than 15 MW, $EF_{grid,y}$ should be calculated as a combined margin (CM), following the guidance in the section “Baselines” in the “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” (ACM0002). As prescribed by ACM0002, the “Tool to calculate emission factor for an electricity system” has been applied as follows in six steps:

Step 1: Identify the relevant electric power system

The project activity displaces electricity generation that would otherwise be generated from the TNEB grid, which is a part of the southern regional grid of India. For the calculation of emission reductions, the Southern India Regional grid, as delineated by the Central Electricity Authority (CEA), may be considered as the reference grid since the TNEB grid is interlinked with other state grids in the region and significant energy exchanges exist between them.

Step2: Select an operating margin method

Out of four methods mentioned, Simple OM approach has been chosen for calculations since in the Southern Regional Grid mix, the low-cost/must run resources constitute less than 50% of total grid generation. Also as mentioned in the CEA CO_2 baseline database for the Indian Power Sector, the two variants "Simple adjusted operated margin" and "Dispatch data analysis operating margin" cannot currently be applied in India due to lack of necessary data.

Data vintage:

For the operating margin calculation, the ex-ante data vintage option is chosen.

Ex ante option: 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, without requirement to monitor and recalculate the emissions factor during the crediting period. The most recent 3 years for which data is available and considered are 2005-06 , 2006-07 and 2007-08.

Step3: Calculation of Operating Margin emission factor:

Operating margin (OM):

Option (a) "Simple OM" has been adopted here. Out of the three options provided for calculating simple OM, "Option A" is chosen and the formula for calculating same is described below:

$$EF_{grid,OMsimple,y} = \sum_{i,m} \frac{FC_{i,m,y}..NCV_{i,y}.EF_{CO2,i,y}}{\sum EG_{m,y}}$$

where,

$EF_{grid,OMsimple,y}$	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$FC_{i,m,y}$	Amount of fossil fuel type "i" consumed by power plant/unit m 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)
$EF_{CO2,i,y}$ y	CO_2 emission factor of fossil fuel type "i" in year y(tCO_2/GJ)
m	All power plants / units serving the grid in year y except low-cost / must-run power plants / units
$EG_{m,y}$	Net electricity generated and delivered to the grid by power plant/unit m in year y (MWh)
i	All fossil fuel types combusted in power plant/unit m in year y
y	The three most recent years for which data is available at the time of submission of the CDM-PDD to the DOE for validation(ex-ante option). The most recent 3 years considered are 2004-05, 2005-06 and 2006-07 .

Step4: Identify the cohort of power units to be included in the build margin

The sample group *m* consists of either:

(a) The five power plants that have been built most recently, or
(b) The power plants capacity additions in the electricity system that comprise 20% of the system generation and that have been built most recently.

Project participants should use from these two options that sample group that comprises the larger annual generation. Since (b) is larger, same is used here.

In terms of vintage of data, project participants can choose between two options. Option 1 is chosen here.

Option 1: For the first crediting period, calculate the build margin emission factor ex-ante based on the most recent information available on units already built for sample group m at the time of CDM-PDD submission to the DOE for validation. This option does not require monitoring the emission factor during the crediting period.

Power plant capacity additions registered as CDM project activities are excluded from the sample group.

Step 5: Calculate the build margin emission factor

The build margin is calculated as the weighted average emissions of recent capacity additions to the reference grid, based on the most recent information available on plants already built for sample group *m* at the time of PDD submission. The PDD has adopted *ex-ante* option for build margin calculation.

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

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 (MWh)
$EF_{EL,m,y}$	CO_2 emission factor of power unit m in year) (tCO_2/MWh)
m	Power units included in the build margin
y	Most recent historical year for which power generation data is available

Step 6: Calculate the combined margin emission factor

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

Where,

w_{OM}	Weight of the operating margin emission factor (0.5 default value as per ACM0002)
$EF_{OM,y}$	Operating margin emission factor calculated as per ACM0002
w_{BM}	Weight of the build margin emission factor (0.5 default value as per ACM0002)
$EF_{BM,y}$	Build margin emission factor calculated as per ACM0002
$EF_{grid,CM,y}$	Combined margin baseline emission factor of the grid

For the Project Activity, the following are the derived baseline values based on the baseline data (As per Annex 3):

1. Operating Margin ($EF_{OM,y}$): 0.998 tCO_2/MWh

2. Build Margin ($EF_{BM,y}$): 0.713 tCO_2/MWh
3. Combined Margin Baseline Emission Factor ($EF_{CM,y}$): 0.85 tCO_2/MWh

B.6.1.3.2 Determination of EG_y:

Where scenario 14 applies, *EGy* is determined based on the average efficiency of electricity generation in the project plant prior to project implementation ($\bullet_{el,pre\ project} = \bullet_{el,baseline\ plant}$) and the average net efficiency of electricity generation in the project plant after project implementation $\bullet_{el,project\ plant,y}$, as follows:

$$EG_y = EG_{projectplant,y} \times \left(1 - \frac{\in_{el,preproject}}{\in_{el,project\ plant,y}} \right)$$

Where:

EG_y	is the net quantity of increased electricity generation as a result of the project activity (incremental to baseline generation) during the year *y* in MWh,
$EG_{project\ plant,y}$	is the net quantity of electricity generated in the project plant during the year *y* in MWh,
$\bullet_{el,pre\ project}$	is the average efficiency of electricity generation in the project plant prior to project implementation, expressed in $MWh_{el}/MWh_{biomass}$. For calculating this, three years data vintage is used as required by ACM0006.
$\bullet_{el,project\ plant,y}$	is average efficiency of electricity generation in the project plant, expressed in $MWh_{el}/MWh_{biomass}$ calculated as below:

$$e_{el,project\ plant,y} = \frac{EG_{project\ plant,y}}{\sum_k NCV_k . BF_{k.y} + \sum_i NCV_i . FF_{project\ plant,i,y}}$$

Where,

NCV_k	is the net calorific value of biomass residue type k in GJ/ton of dry matter
$BF_{k,y}$	is the quantity of biomass residue type k combusted in the project plant
during	the year y in tons of dry matter.
NCV_i	is the net calorific value of fossil fuel type i in GJ/ton

$FF_{project\ plant,i,y}$ is the quantity of fossil fuel type i combusted in the project plant during year y in mass unit per year

B.6.1.4 Emission reductions due to displacement of heat:

In the case of cogeneration plants, project participants shall determine the emission reductions or increases due to displacement of heat ($ER_{heat,y}$).

In scenario 14, heat and electricity in the absence of the project activity is generated in a low pressure low efficiency cogeneration plant, i.e. the efficiency of electricity generation is lower than in the project plant. The efficiency of heat generation, i.e. the heat generated per quantity of biomass residue fired, may differ between the project plant and the plant prior to the implementation of the project activity i.e. in the baseline scenario. This implies that the project implementation may result in lower quantity of heat generation compared to the baseline scenario. This may result in additional heat generation from other sources resulting in GHG emissions. As described in ACM0006, to address this substitution effect, project participants may either

(a) demonstrate that the thermal efficiency in the project plant is larger or similar compared with the thermal efficiency of the plant considered in the baseline scenario (i.e., $\varepsilon_{th,project\ plant} \geq \varepsilon_{th,baseline\ plant(s)}$) and then assume $ER_{heat,y} = 0$

or, if this is not the case,

(b) account for any increases in CO_2 emissions,

In the project activity case, (a) is true (i.e., the efficiency of heat generation in the project plant is equal to that of the baseline plant).

$\varepsilon_{th,project\ plant}$ (0.722 $MWh_{th}/MWh_{biomass}$) $\geq \varepsilon_{th,baseline\ plant}$ (0.670 $MWh_{th}/MWh_{biomass}$).

Therefore, it is assumed that $ER_{heat,y} = 0$ for this project activity. Refer to CER calculation sheet for details.

B.6.1.5: Leakage:

ACM0006 states "The main potential source of leakage for this project activity is an increase in emissions from fossil fuel combustion due to diversion of biomass from other uses to the project plant as a result of the project activity. Where the most likely baseline scenario is the use of the biomass for energy generation (scenarios 1, 4, 6, 8, 9, 11, 12, 13 and 14), the diversion of biomass to the project activity is already considered in the calculation of baseline reductions. In this case, leakage effects do not need to be addressed." The project activity falls under scenario 14 of ACM0006 and therefore does not require addressing leakage. There is no leakage of emission reductions for this project activity.

B.6.1.6: Emission reductions

The project activity mainly reduces CO_2 emissions through substitution of power generation with fossil fuels by energy generation with biomass residues. The emission reduction ER_y by the project activity during a given year y is the difference between the emission reductions through substitution of electricity generation with fossil fuels ($ER_{electricity,y}$), the emission reductions through substitution of heat generation with fossil fuels ($ER_{heat,y}$), project emissions (PE_y), emissions due to leakage (L_y) as follows:

$$ER_y = ER_{heat,y} + ER_{electricity,y} + BE_{biomass,y} - PE_y - L_y$$

Where:

ER_y	Emissions reductions of the project activity during the year y (tCO_2/yr)
$ER_{electricity,y}$	Emission reductions due to displacement of electricity during the year y (tCO_2/yr)
$ER_{heat,y}$	Emission reductions due to displacement of heat during the year y (tCO_2/yr). This parameter is equal to zero since efficiency of heat generation in the project scenario is same as the baseline scenario. $ER_{heat,y} = 0$.
$BE_{biomass}$	Baseline emissions due to biomass decay. This parameter is excluded from the project boundary and therefore is equal to zero. $BE_{biomass} = 0$.
PE_y	Project emissions during the year y (tCO_2/yr)
L_y	Leakage emissions during the year y (tCO_2/yr). For scenario 14, leakage need not be separately estimated and therefore Ly = 0.

Since $ER_{heat,y} = 0$, $BE_{biomass,y}$ and $L_y = 0$ for this project activity (Refer section B.6.1.3 and B.6.1.4 above), the above equation reduces to:

$ER_y = ER_{electricity,y} - PE_y$

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

(Copy this table for each data and parameter)

Data / Parameter:	$e_{el,existing\ plant(s)}$
Data unit:	MWhe/MWhbiomass
Description:	Average net efficiency of electricity generation in the existing power / cogeneration plant(s) fired with the same type of biomass residue at the project site
Source of data used:	On-site measurements
Value applied:	0.0395
Justification of the choice of data or description of measurement methods and procedures actually applied :	Measure the quantity of fuels fired and the electricity generation during a representative time period and divide the quantity of fuels fired. The most recent historical years prior to project plant commissioning (Jan 2001 to July 2002) for which data is available have been be used to determine the average efficiency. Since the turbines are back-pressure type with no extractions, variations are not expected and the above time frame is suitable. As per guidelines of ACM0006 version 09.
Any comment:	-

Data / Parameter:	$e_{th,existing\ plant(s}$
Data unit:	MWhth/MWhbiomass
Description:	Average net efficiency of heat generation in the existing power / cogeneration plant(s) fired with the same type of biomass residue at the project site
Source of data used:	On-site measurements
Value applied:	0.670

Justification of the choice of data or description of measurement methods and procedures actually applied :	Measure the quantity of fuels fired and the heat generation during a representative time period and divide the quantity of fuels fired. The most recent historical years prior to project plant commissioning (Jan 2001 to July 2002) for which data is available have been be used to determine the average efficiency. Since the turbines are back-pressure type with no extractions, variations are not expected and the above time frame is suitable. As per guidelines of ACM0006 version 09.
Any comment:	-

Data / Parameter:	**$EF_{electricity}$**
Data unit:	tCO_2/MWh
Description:	Combined margin baseline emission factor of the southern regional grid
Source of data used:	CEA/IPCC
Value applied:	0.85
Justification of the choice of data or description of measurement methods and procedures actually applied :	The project participants have chosen to calculate this value on an ex-ante basis once in the beginning of the project activity. This will not be updated annually. Calculated as per ACM0002 guidelines using data from CEA/IPCC. Refer annex 3 for details.
Any comment:	More details in Annexure 3

B.6.3. Ex-ante calculation of emission reductions:

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The following tables show the calculation of emission reductions using the formula mentioned in section B.6.1.

Project emissions:

Emissions due to combustion of fossil fuels in the project activity:					
S.No	**Notation**	**Parameter**	**Unit**	**Value**	**Comments**
1	$FF_{project\ plant,y}$	Quantity of fossil fuel used	T/yr	0	Will be measured if used. Envisaged only during emergencies.

2	$FF_{projectsite,y}$	Quantity of fossil fuel used	T/yr	0	Will be measured if used. Envisaged only during emergencies.
3	NCV	Calorific Value	TJ/T	0	Will be measured if used. Envisaged only during emergencies.
4	$EF_{CO2,FF,i}$	CO_2 emission factor	tCO_2/TJ	0	IPCC default value for the specific fuel used would be adopted when used.
5	$PEFF_y$ ((1+2)*3*4)	CO_2 emissions from coal	tCO_2/yr	0	Methodology formula.

Emissions due to combustion of fossil fuels for transportation of biomass:					
6	N_y	Number of truck trips during the year y		0	No outside biomass residue purchase envisaged. Will be measured when used.
7	AVD_y	Average return trip distance between the biomass fuel supply sites and the project plant	kms	0	No outside biomass residue purchase envisaged. Will be measured when used.
8		Truck fuel economy for 10 tonne truck	Kms/litre of fuel	-	No outside biomass residue purchase envisaged. Will be measured when used.
9		Truck fuel economy	Litres/000'kms	-	Will be calculated based on above data.
10		Density of diesel	Kg/litre of fuel	0.85	Bureau of Energy Efficiency reference material
11		Fuel consumption per 1000 kilometer for 10 tonne truck	kg/000'kms	-	Will be calculated based on above data.
12		CO_2 emission factor	$kgCO_2$/kg fuel	3.16	IPCC 2006 guidelines default value for diesel.
13	$EF_{km,CO2}$ (11*12)	Average CO_2 emission factor of the trucks	$kgCO_2/km$	0	Will be determined when outside biomass is purchased

14	PET_y (6*7*13)	CO_2 emissions from diesel	tCO_2	0	Methodology formula. Refer section B.6.1.1 above.
15	PE_y (5+14)	Total Project Emissions	tCO_2	0	Methodology formula. Refer section B.6.1.1 above.

Emission reductions due to displacement of electricity:

Determination of EGy:					
S.No	**Notation**	**Parameter**	**Unit**	**Value**	**Comments**
1	EGpre-project,y	Generation from the pre-project 4.5 MW, 32 Kg/cm2 system in the period Jan 2001 to July 2002	MWhe	39,284.07	Actual values recorded by BASL. As per consolidated monthwise energy and mass balance calculated based on daily cogeneration report.
2	BFpre-project,y	Fuel Consumption (4.5 MW system) in the period Jan 2001 to July 2002	T (dry)	234,990.52	Actual values recorded by BASL. As per consolidated month-wise energy and mass balance for the years calculated based on daily cogeneration report.
3	• $BF_{pre-project,k,y}$. $NCV_{,k,y}$	Heat equivalent of pre-project fuel consumption	MWhth	993,852.73	Based on average NCV of dry bagasse
4	$•_{el, pre-project}$ (1/3)	Pre-project efficiency	MWhe/ MWhth	0.0395	Average efficiency achieved during the pre-project years. Refer CER excel sheet.

5	EGproject plant,y	Estimated generation from the 20 MW, 87 Kg/cm^2 system	MWhe	118,988	Based on 90% load factor and annual bagasse availability. Refer CER excel sheet.
6	BFproject plant,y	Fuel Consumption (New 20 MW system)	T (dry)	146,458	Based on 250 sugar crushing days operation at 4000 Tonnes cane crushed per day and 29% bagasse on cane.
7	• $BF_{project\ plant,k,y}$ · $NCV_{,k,y}$	Fuel Consumption in heat equivalent	MWh	618616	Based on average NCV of dry bagasse
8	•$_{el,\ project\ plant,y}$ (5/7)	Project plant efficiency	MWhe/ MWhth	0.1923	Calculation as per ACM0006 formula
9	EGy (5* (1- (4/8)))	Incremental Energy generation from the project activity	MWh	94,571	ACM0006 formula. Refer section. Refer section B.6.1.2 above.

S.No	**Notation**	**Parameter**	**Unit**	**Value**
10	EG_y	Incremental Energy generation from the project activity	MWhe/yr	94,571
11	$EF_{electricity}$	Baseline emission factor for grid	tCO_2/MWh	0.85
12	$ER_{el},_y$ (10*11)	Electricity emission reduction	tCO_2/yr	80,385

Net Emission reductions

S.No	**Notation**	**Parameter**	**Unit**	**Value**
1	$ER_{el},_y$	Electricity emission reductions	tCO_2/yr	80,385
2	PE_y	Project emissions	tCO_2/yr	0
3	ER_y (1-2)	Emission reductions	tCO_2/yr	80,385

There are no uncertainties in the estimation of emission reductions as all the critical values used are based on actual data. For detailed calculations, please refer excel sheets enclosed as appendix to this PDD.

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

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Year	Estimation of project activity emission (tCO_2e)	Estimation of baseline emissions (tCO_2e)	Estimation of leakage (tCO_2e)	Estimation of overall emission reductions (tCO_2e)
2011-12	**0**	80,385	**0**	80,385
2012-13	**0**	80,385	**0**	80,385
2013-14	**0**	80,385	**0**	80,385
2014-15	**0**	80,385	**0**	80,385
2015-16	**0**	80,385	**0**	80,385
2016-17	**0**	80,385	**0**	80,385
2017-18	**0**	80,385	**0**	80,385
2018-19	**0**	80,385	**0**	80,385
2019-20	**0**	80,385	**0**	80,385
2020-21	**0**	80,385	**0**	80,385
Total (tonnes of CO_2e)	**0**	803,850	**0**	803,850

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

Data / Parameter:	**$BF_{k,y}$**
Data unit:	Tonnes
Description:	Quantity of biomass type *k* combusted in the project plant during year y
Source of data to be used:	ACM0006 recommends “on-site measurements using weight or volume meters”. Bagasse combustion is monitored based on on-site measurement of parameters as described below in “Description of measurement methods”. Recorded in BASL fuel log books.

Value of data applied for the purpose of calculating expected emission reductions in section B.5	146458
Description of measurement methods and procedures to be applied:	Fuel consumption is measured continuously in on-line weighing scale installed in the fuel conveyors. This data is recorded on a daily basis by Technician (Mechanical) in fuel log books. Reporting and archiving: Data recorded by Technician is reviewed and input to the computer by the Shift Engineer (SE). On a monthly basis, a compilation of all the Energy-CDM parameters recorded for the month would be prepared by the SE and submitted to the Cogen head. The Cogen head would verify the monthly energy-CDM report and archive it. This gives the wet fuel quantity. The dry fuel quantity is calculated by adjusting for the moisture content as follows: Dry fuel = Wet fuel * (100- moisture %)
QA/QC procedures to be applied:	The measured values are cross-checked with an annual fuel balance based on monthly/annual manufacturing reports, purchase receipts and stock exchanges and are found to be consistent. “Fuel combusted = Fuel generated in-house + Fuel purchased + Opening stock - Closing stock in fuel yard”
Any comment:	-

Data / Parameter:	$BF_{T,k,y}$
Data unit:	Tonnes
Description:	Quantity of biomass type *k* that has been transported to the project site during year y
Source of data to be used:	ACM0006 recommends “on-site measurements using weight or volume meters”. Bagasse transported is monitored based on on-site measurement of parameters as described below in “Description of measurement methods”. Recorded in BASL fuel log books.

Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 (Outside biomass purchase expected only during emergencies like drought. Since this is not likely to occur in normal years, this parameter is considered as zero for the estimation.)
Description of measurement methods and procedures to be applied:	Fuel transported is measured continuously in a weigh bridge installed at the factory entrance. This data is recorded continuously by the stores department. Reporting and archiving: Data recorded by stores operator is reviewed and input to the computer by the Shift Engineer (SE). On a monthly basis, a compilation of all the Energy-CDM parameters recorded for the month would be prepared by the SE and submitted to the Cogen head. The Cogen head would verify the monthly energy-CDM report and archive it. This gives the wet fuel quantity. The dry fuel quantity is calculated by adjusting for the moisture content as follows: Dry fuel = Wet fuel * (100- moisture %)
QA/QC procedures to be applied:	The measured values are cross-checked with an annual fuel balance based on monthly/annual manufacturing reports, purchase receipts and stock exchanges and are found to be consistent. “Fuel combusted = Fuel generated in-house + Fuel purchased + Opening stock - Closing stock in fuel yard”
Any comment:	-

Data / Parameter:	***Moisture content of the biomass residues***
Data unit:	% water content
Description:	Moisture content of each biomass residue type k
Source of data to be used:	Lab chemist log book

Value of data applied for the purpose of calculating expected emission reductions in section B.5	50.5 % (for Bagasse)
Description of measurement methods and procedures to be applied:	The moisture content is measured on-site using the “weights method” described below and recorded in log books and electronic records. Weights method: The weight of fuel with moisture and without moisture (after drying in oven) is measured to arrive at the moisture content. This data is recorded on a daily basis by Lab-in-Charge (LIC) in fuel log books. Reporting and archiving: Data recorded by LIC is reviewed and input to the computer by the Shift Engineer (SE). On a monthly basis, a compilation of all the Energy-CDM parameters recorded for the month would be prepared by the SE and submitted to the Cogen head. Mean values are calculated monthly and recorded in monthly report.
QA/QC procedures to be applied:	Equipments used like mass balances would be calibrated periodically.
Any comment:	-

Data / Parameter:	**AVD_y**
Data unit:	Kilometres (Kms)
Description:	Average return trip distance between biomass fuel supply sites and the project site
Source of data to be used:	Records by BASL on the origin of the biomass – Will be recorded in biomass purchase log books based on information provided by truck operators.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	- (Outside biomass purchase expected only during emergencies like drought. Since this is not likely to occur in normal years, this parameter is considered as zero for the estimation.)

Description of measurement methods and procedures to be applied:	The truck operator will provide the distance travelled by the truck between the fuel supply site and the project activity. Frequency of monitoring: Continuously
QA/QC procedures to be applied:	Consistency of distance records provided by the truckers will be checked by comparing recorded distances with information from other sources.
Any comment:	This data is used to calculate project emissions from biomass transportation

Data / Parameter:	**Ny**
Data unit:	-
Description:	Number of truck trips for transportation of biomass
Source of data to be used:	On-site measurements BASL biomass purchase records. Recorded by the BASL weigh bridge operator
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 (Outside biomass purchase expected only during emergencies like drought. Since this is not likely to occur in normal years, this parameter is considered as zero for the estimation.)
Description of measurement methods and procedures to be applied:	Continuously. The number of truck trips from each source is recorded at the weigh bridge. The stores department operator at the weigh bridge records each and every truck load before biomass is unloaded. All details including the weight of biomass and source of biomass are recorded by the operator in BASL records.
QA/QC procedures to be applied:	The consistency of the number of truck trips will be checked with the quantity of biomass combusted.
Any comment:	-

Data / Parameter:	$\mathbf{EF_{km,\,CO2}}$
Data unit:	t CO_2/km
Description:	Average CO_2 emission factor for transportation of biomass with trucks
Source of data to be used:	Sample measurements of the fuel type, fuel consumption and distance traveled for all truck types. Calculate CO2 emissions from fuel consumption by multiplying with appropriate net calorific values and CO2 emission factors. For net calorific values and CO2 emission factors, reliable national default values or, if not available, (country-specific) IPCC default values would be used.

Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 (Outside biomass purchase expected only during emergencies like drought. Since this is not likely to occur in normal years, this parameter is considered as zero for the estimation.)
Description of measurement methods and procedures to be applied:	Sample measurements would be conducted to determine the fuel efficiency (kms/litre fuel) of the trucks by monitoring the fuel type, fuel consumption and distance travelled for all truck types. This is multiplied with the net calorific value of diesel (based on Central Electricity Authority data) and its CO_2 emission factor (IPCC default values). Monitoring frequency: Annually
QA/QC procedures to be applied:	Cross-check measurement results with literature
Any comment:	Average CO_2 emission factor for transportation of biomass with trucks

Data / Parameter:	$\mathbf{EF_{CO2,FF,\,i}}$
Data unit:	tCO_2/TJ
Description:	CO_2 emission factor for fossil fuel type i
Source of data to be used:	Either measurements would be conducted or accurate and reliable local or national data would be used if available. Where such data is not available, IPCC default emission factors (country-specific, if available) would be used if they are deemed to reasonably represent local circumstances.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	- (Envisaged only during emergencies. Actual value would be monitored based on type of fossil fuel used)
Description of measurement methods and procedures to be applied:	Analysis of samples of specific fossil fuel used would be conducted at reputed laboratories once in six months whenever fossil fuel is used.
QA/QC procedures to be applied:	Check consistency of measurements and local / national data with default values by the IPCC. If the values differ significantly from IPCC default values, possibly collect additional information or conduct measurements.
Any comment:	

Data / Parameter:	$\mathbf{FF_{project\ plant\ i,y}}$
Data unit:	Tonnes

Description:	Onsite fossil fuel consumption of type 'i' for co-firing in the project plant
Source of data to be used:	BASL boiler fuel log books
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 (Envisaged only during emergencies. Actual value would be monitored when used)
Description of measurement methods and procedures to be applied:	Fuel consumption would be measured continuously in on-line weighing scale installed in the fuel conveyors. This data would be recorded on a daily basis by Technician (Mechanical) in fuel log books. Reporting and archiving: Data recorded by Technician is reviewed and input to the computer by the Shift Engineer (SE). On a monthly basis, a compilation of all the Energy-CDM parameters recorded for the month would be prepared by the SE and submitted to the Cogen head. The Cogen head would verify the monthly energy-CDM report and archive it. Monitoring frequency: Continuously
QA/QC procedures to be applied:	Cross-check the measurements with an annual energy balance that is based on purchased quantities and stock exchanges.
Any comment:	

Data / Parameter:	**$FF_{project\ site\ i,y}$**
Data unit:	Tonnes
Description:	Onsite fossil fuel consumption of type 'i' used in the project site apart from co-firing as a result of the project activity. Only that fossil fuel consumption attributable to the energy efficiency improvement would be included in this parameter.
Source of data to be used:	BASL fuel consumption log books
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0 (Envisaged only during emergencies. Actual value would be monitored when used)

Description of measurement methods and procedures to be applied:	The quantity of fossil fuel is measured in volume or weight meters. Monitoring frequency: Continuously.
QA/QC procedures to be applied:	Cross-check the measurements with an annual energy balance that is based on purchased quantities and stock exchanges. No potential conflict of interest in conservative data monitoring as no other type of benefit is available for recording a lower quantity of fossil fuel consumption than actually consumed.
Any comment:	

Data / Parameter:	**$EG_{project\ plant,y}$**
Data unit:	MWh
Description:	Net quantity of electricity generated in the project plant during the year y
Source of data to be used:	BASL energy meter log books
Value of data applied for the purpose of calculating expected emission reductions in section B.5	118,988
Description of measurement methods and procedures to be applied:	This gross generation and auxiliary consumption would be measured continuously in energy meters. Net generation is arrived by deducting the auxiliary consumption from the gross electricity generation. $EG_{project\ plant}$ = Gross generation – Auxiliary consumption. The Technician (Electrical) records the net generation data on a daily basis in log books. The data will be recorded in log books on a daily basis based on energy meters of BASL. Monitoring frequency: Continuously
QA/QC procedures to be applied:	The consistency of the recorded net electricity generation will be cross-checked with receipts from energy sales and the quantity of fuel fired (e.g. check whether the electricity generation divided by the quantity of fuel fired results in a reasonable efficiency that is comparable to previous years) No potential conflict of interest in conservative data recording.
Any comment:	-

Data / Parameter:	**NCV_i**
Data unit:	GJ/ton

Description:	Calorific value of fossil fuel type i
Source of data to be used:	Analysis report of reputed laboratory
Value of data applied for the purpose of calculating expected emission reductions in section B.5	- (Actual value would be monitored based on type of fossil fuel used)
Description of measurement methods and procedures to be applied:	Determined by a third party laboratory. Every six months, the lab technician would collect and sends three samples to the third party laboratory. The analysis reports are reviewed and archived by the Cogen head. Monitoring frequency: Third party analysis once in six months taking three samples per analysis
QA/QC procedures to be applied:	Check consistency of measurements and local / national data with default values by the IPCC. If the values differ significantly from IPCC default values, possibly collect additional information or conduct measurements.
Any comment:	The value will be determined when fossil fuel is used.

Data / Parameter:	**NCV_k**
Data unit:	GJ/ton of dry matter
Description:	Net calorific value of biomass residue type *k*
Source of data to be used:	Analysis report of reputed laboratory
Value of data applied for the purpose of calculating expected emission reductions in section B.5	15.21 for bagasse (3632 kcal/kg) – historical average
Description of measurement methods and procedures to be applied:	Determined by a third party laboratory. Every six months, the lab technician would collect and send three samples to the third party laboratory. The analysis reports are reviewed and archived by the Cogen head. Monitoring frequency: Third party analysis once in six months taking three samples per analysis

QA/QC procedures to be applied:	Check consistency of measurements and local / national data with default values by the IPCC. If the values differ significantly from IPCC default values, possibly collect additional information or conduct measurements. No potential conflict of interest in conservative data recording.
Any comment:	

Data / Parameter:	**EC $_{PJ,y}$**
Data unit:	MWh
Description:	On-site electricity consumption attributable to the project activity during the year *y*
Source of data to be used:	On-site measurements
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0
Description of measurement methods and procedures to be applied:	Electricity meters are used. The quantity shall be cross-checked with electricity Purchase receipts. Monitoring frequency: Continuously.
QA/QC procedures to be applied:	The measurement results are cross-checked with invoices for purchased electricity if available.
Any comment:	**-**

Data / Parameter:	**EF $_{EL,j,y}$**
Data unit:	tCO_2/MWh
Description:	Emission factor for electricity generation for source j in year y
Source of data used:	Tool to calculate baseline, project and/or leakage emissions from electricity consumption
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1.3
Description of measurement methods and procedures to be applied:	Default value from the “Tool to calculate baseline, project and/or leakage emissions from electricity consumption” is adopted
QA/QC procedures to be applied:	-

Any comment:	This parameter is used in calculating project emission from electricity consumption in the project activity

Data / Parameter:	**TDL $_{j,y}$**
Data unit:	%
Description:	Average technical transmission and distribution losses for providing electricity to source j in year y
Source of data to be used:	On-site measurements. Default value of 20% of electricity consumption is used.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	20
Description of measurement methods and procedures to be applied:	The parameter $TDL_{j,y}$ is calculated for the distribution and transmission networks of the electricity grid of the same voltage as the connection where the proposed CDM project activity is connected to.Monitoring frequency: Annually.
QA/QC procedures to be applied:	The measurement results are cross-checked with invoices for purchased electricity if available.
Any comment:	**-**

B.7.2. Description of the monitoring plan:

>>

Bannari Amman Sugars Limited will incorporate a special team for implementing the monitoring procedures as described in section B7.1. The team will comprise of relevant personnel from various departments, who will be assigned the task of monitoring and recording specific CDM parameters relevant to their department. The monitored values will be periodically cross-checked by the respective department heads and sent to the CDM team head for compilation and analysis. Any deviation of monitored values from estimated values will be investigated and appropriate action would be taken. The monitored values would be recorded and stored in paper and electronically for verification. Elaborate monitoring information is provided in Annexure 4.

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

>>

21/12/2009

Name of person/entity determining the baseline:

M/s. Bannari Amman Sugars Limited

1212, Trichy Road

Coimbatore

Tamilnadu - 641018

The entity is a project participant listed in annex 1 to this document

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:

>>
05/03/2001

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

>>

20 years 0 months

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:

>>
Not Applicable

C.2.1.2. Length of the first crediting period:

>>
Not Applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>
01/01/2011 or date of registration of the project activity, whichever is later

C.2.2.2. Length:

>>
10 years 0 months

SECTION D. Environmental impacts

>>

D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

>>

A rapid assessment of Environmental Impact due to the project activity has been carried out and the report summary is available as Appendix - 2. The cogeneration power plant uses environmentally sustainable bagasse as fuel, which leads to zero net GHG emissions. The GHG emissions of the combustion process, mainly CO_2, will be consumed by sugar cane plant species, representing a cyclic process.

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:

>>

A host party regulation requires BASL to obtain environmental clearance in the form of "No Objection Certificate" from the TamilNadu Pollution Control Board (TNPCB). The other condition is that the site of the project has to be approved from the environmental angle and that the Environmental Management Plans (EMPs) are to be prepared and submitted to the pollution control board. The assessment of environmental impacts due to the project activity has been carried out to understand if there are any significant environmental impacts and a management plan has been prepared to minimise adverse environmental impact. The study indicates that the impact of the project is not significant.

The following documents were obtained from the TamilNadu (State) Pollution Control Board (TNPCB) for the project activity (20 MW bagasse based cogeneration plant) towards environmental clearance:

- Consent under Section 21 of the Air (Prevention and Control of Pollution) Act, 1981 (Central Act 14 of 1981) as amended
- Consent under Section 25/26 of the Water (Prevention and Control of Pollution) Act, 1974 (Central Act 6 of 1974) as amended

The Environmental Impact Assessment (EIA) notification of the Ministry of Environment and Forests (MoEF) is not applicable as the project activity does not fall under its purview.

SECTION E. Stakeholders' comments

>>

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

>>

BASL organised a formal meeting to appraise the local stakeholders about the project activity and receive their comments. BASL sent (through mail) formal invitations to individual stakeholders well in advance of the consultation meeting indicating the date, time and venue. The following stakeholders were identified:

- Local panchayat/residents
- Local farmers/cane growers' associations
- Local Non Governmental Organisations (NGOs)
- Tamil Nadu Electricity Board (TNEB)
- Tamil Nadu Pollution Control Board (TNPCB)

The stakeholder meeting was conducted on 04.09.2003 at the sugar plant conference hall and was attended by the local stakeholders. BASL representatives appraised the stakeholders about the various aspects of the project activity. Doubts raised by stakeholders were clarified by BASL. The stakeholders discussed on the project activity and provided their views on it. BASL collected written comments of the project activity from the stakeholders.

E.2. Summary of the comments received:

>>

All the stakeholders in the meeting provided positive comments on the project activity and appreciated BASL for implementing the project activity. The stakeholders were glad that the project is contributing to reducing environmental pollution. Further, BASL has obtained clearances from TNPCB and TNEB for the implementation of the project activity. No negative comments were received from any of the stakeholders. The query raised by the *Head-Village Panchayat* and the clarification provided by BASL are provided below:

Query: "*How is the air pollution in the area reduced by the project activity?*"

BASL response: "*In the old low pressure cogeneration set up, rotary air valves (RAV) were present to reduce the particulate matter escaping from the flue gas. These RAVs cannot control fine particles and as a result lot of dust particles and unburnts escaped with flue gas and settled as deposits in the near by areas. However, in the new project activity, latest Electro Static*

Precipitators (ESPs) are installed. The ESPs collect even fine particles from the flue gas and drastically reduces solid particles in the out going flue gas"

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

>>

Since all the stakeholder comments were positive and no negative comments were received, no corrective action was undertaken as no negative comments were received.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Bannari Amman Sugars Limited
Street/P.O.Box:	1212, Trichy Road
Building:	Bannari Amman Sugars Limited
City:	Coimbatore
State/Region:	Tamilnadu
Postcode/ZIP:	641018
Country:	India
Telephone:	91-422-2305454
FAX:	91-422-2305454
E-Mail:	finance@bannari.com
URL:	www.bannari.com
Represented by:	
Title:	Vice President (Finance)
Salutation:	Mr.
Last name:	R
Middle name:	
First name:	Murugesan
Department:	Finance
Mobile:	
Direct FAX:	
Direct tel:	
Personal e-mail:	rmurugesan@bannari.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

No public funding from annex-1 parties are involved in the project activity

Annex 3
BASELINE INFORMATION

The Central Electricity Authority (CEA) has published the baseline emission factors database for the various electricity grids in India. The emission factors have been calculated based on UNFCCC guidelines (based on ACM0002). For further details on the calculation methods and data used, please refer the following web-link:

http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

In the CEA database, the simple operating margin, build margin and combined margin emission factors of the regional electricity grids have been provided separately for two cases; Including electricity imports and Excluding electricity imports from other regional grids. Since, emission factors excluding imports are lower, the same has been considered as a conservative approach. The combined margin emission factor for the southern regional grid (0.85 tCO_2/MWh) has been considered for this project activity.

CENTRAL ELECTRICITY AUTHORITY: CO2 BASELINE DATABASE			
VERSION			**4.0**
DATE			**Sep-08**
BASELINE METHODOLOGY			
ACM0002 / Ver 07 and "Tool to Calculate the Emission Factor for an Electricity System", Version 1.1			
EMISSION FACTORS			
Weighted Average Emission Rate (tCO2/MWh) (excl. Imports)			
	2005-06	2006-07	2007-08
NEWNE	0.84	0.83	0.82
South	0.73	0.72	0.72
India	0.82	0.80	0.80
Simple Operating Margin (tCO2/MWh) (excl. Imports)			
	2005-06	2006-07	2007-08
NEWNE	1.02	1.02	1.01
South	1.01	1.00	0.99
India	1.02	1.01	1.01
Build Margin (tCO2/MWh) (excl. Imports)			
	2005-06	2006-07	2007-08
NEWNE	0.67	0.63	0.60
South	0.71	0.70	0.71

India	0.68	0.65	0.63
Combined Margin (tCO2/MWh) (excl. Imports)			
	2005-06	2006-07	2007-08
NEWNE	0.85	0.82	0.80
South	0.86	0.85	0.85
India	0.85	0.83	0.82

Table T3.1: Mass and Energy balance of the pre-project, project and background scenarios

Parameter	Unit	Pre-project scenario	Project scenario	Earlier background scenario[30]	Remarks
Crushing capacity	TCD[31] TCH[27]	4000 166.67	4000 166.67	2500 104.17	
Specific power consumption of sugar plant	kWh/T	25	25	25	Technical paper by renowned sugar cogeneration consultants
Power required for rated crushing capacity	MW	4.17	4.17	2.60	25*166.67 = 4166 kW
Power export	MW	-	13-14	-	DPR
Power generation including auxiliary load	MW	4.42	19-20	2.80	
Specific steam consumption of sugar plant	% on cane	42	42	42	Technical paper by renowned sugar

[30] Provided as a reference for better understanding of the sugar plant's background. This is not linked to the pre-project scenario. The expansion from 2500 TCD to 4000 TCD was done in year 1999 whereas the project activity commenced much later in March 2001.

[31] Tonnes Cane per Day, Tonnes Cane per Hour.

					cogeneration consultants
Process steam required for rated crushing capacity	TPH	70	70	43.75	42%*166.67 TPH = 70 TPH
Bagasse required for rated steam generation	TPH	48	48	30	CE certificate
Rated power capacity of TGs	MW	4.5	20	4.5	TG specifications
Rated steam capacity of boilers	TPH	70	120	70	Boiler specifications
Rated bagasse firing capacity of boilers	TPH	50	50	50	CE certificate

Figure F1: Pre-project Scenario (4000 TCD)

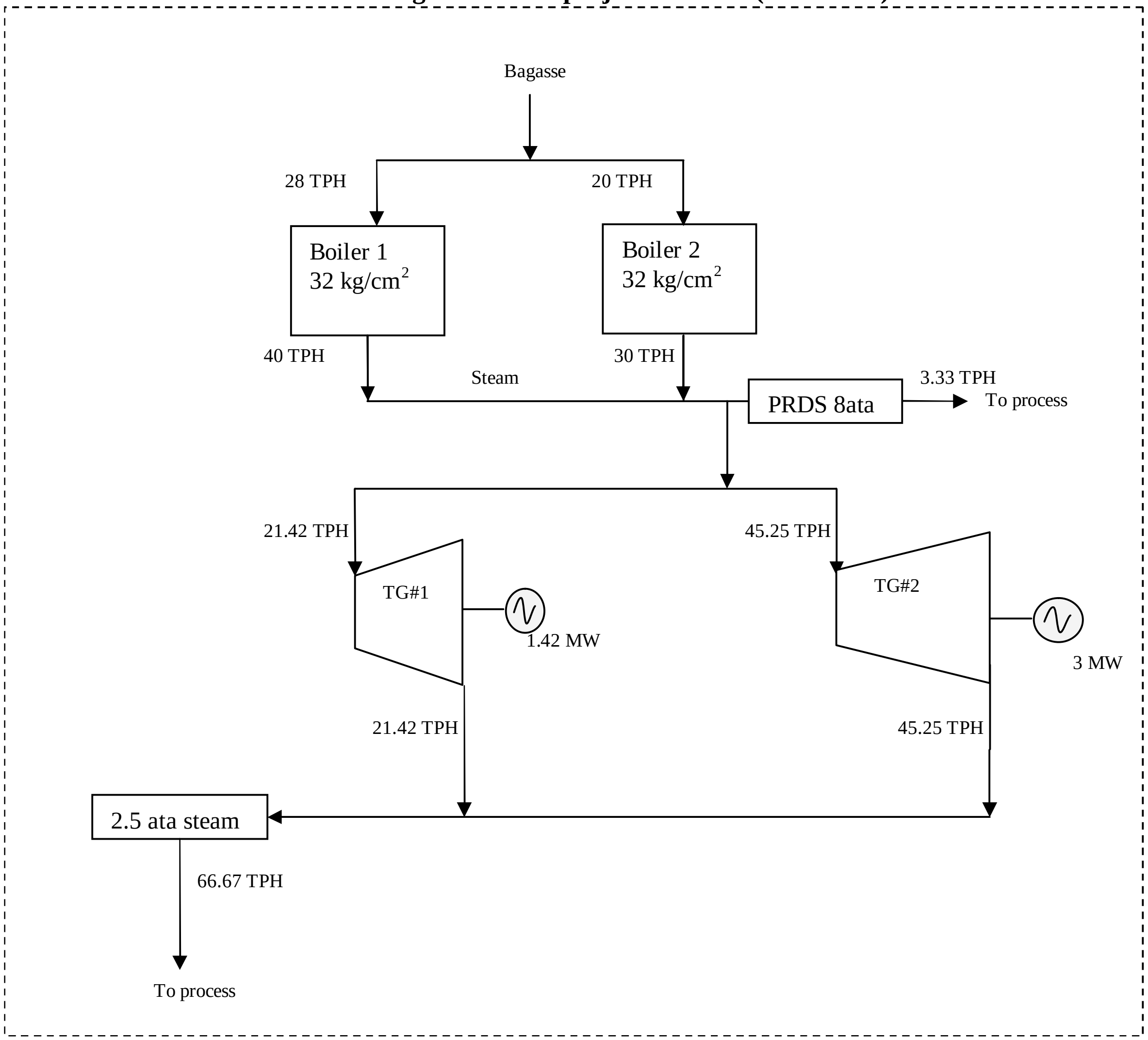


Figure F2: Project scenario (4000 TCD)

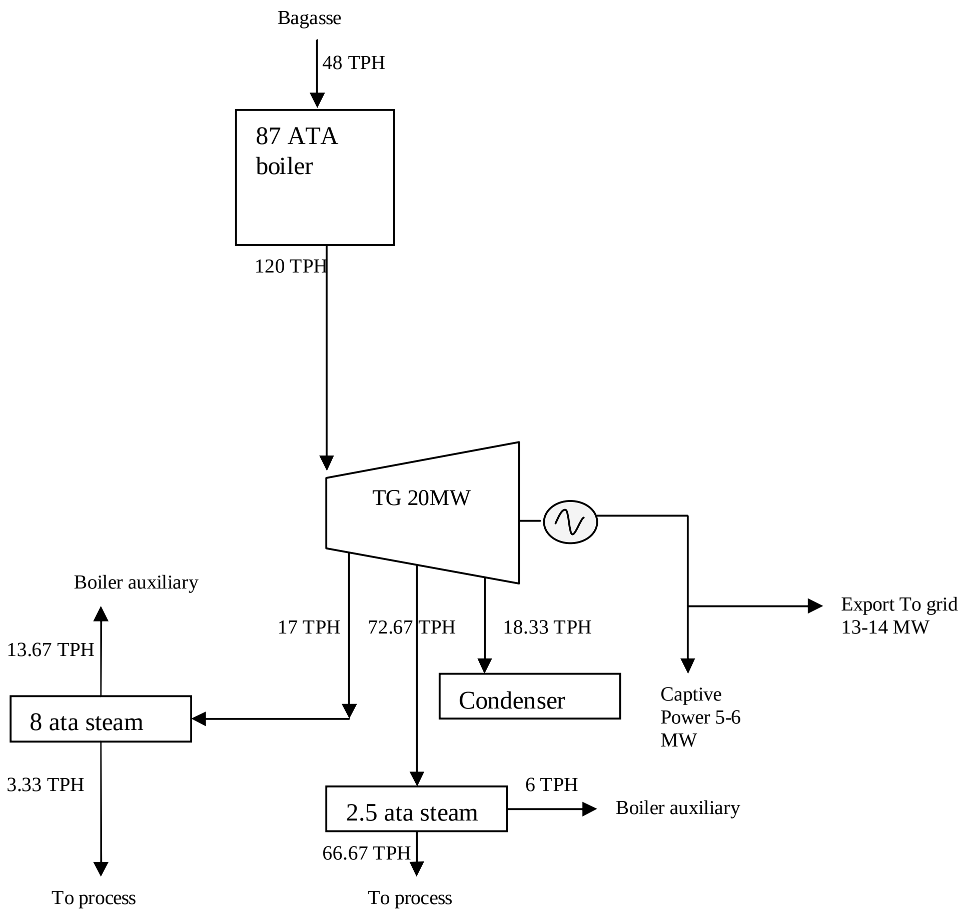


Figure F3: Earlier background Scenario (2500 TCD)

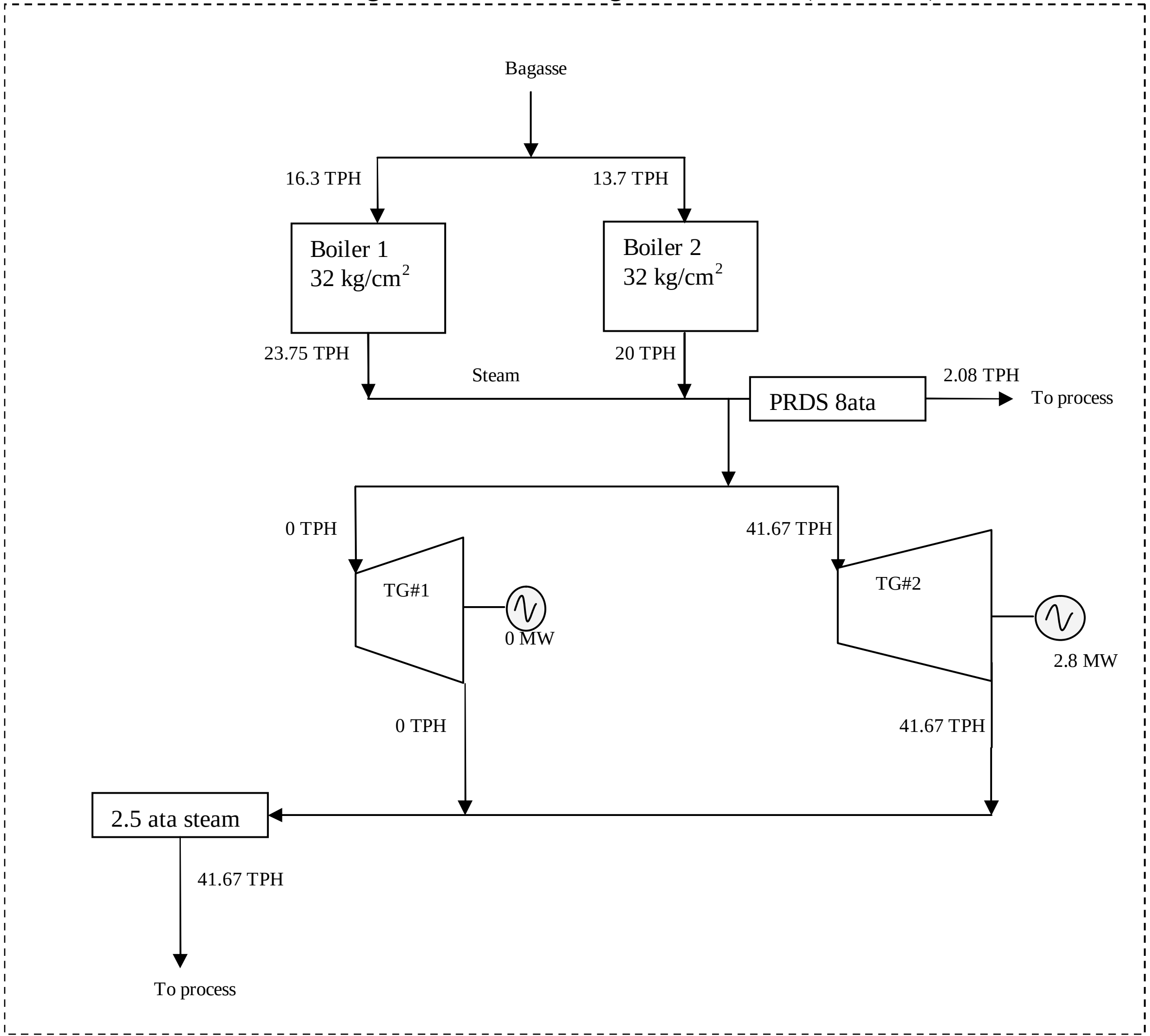


Table 3.2 Energy requirement of the 4000 TCD sugar plant and capacity of existing cogeneration plant

Parameter	**Unit**	**Value**	**Remarks**
Crushing capacity	TCD TPH	4000 166.67	
Specific power consumption of sugar plant	kWh/Tonne of Cane	25	Technical paper by renowned sugar cogeneration consultants
Power required for 4000 TCD	MW	4.17	25*166.67 = 4166 kW
Specific steam consumption of sugar plant	% on cane	42	Technical paper by renowned sugar cogeneration consultants
Power Generation (including auxiliaries)	MW	4.42	
Steam required for rated crushing capacity with 42% steam consumption	TPH	70	42%*166.67 TPH = 70 TPH
Bagasse required for above steam generation (wet basis)	TPH	48	Boiler parameter
Capacity of existing system			
Rated power capacity	MW	4.5	Sufficient
Rated steam capacity	TPH	70	Sufficient
Rated bagasse firing capacity of boilers	TPH	50	Sufficient

Annex 4

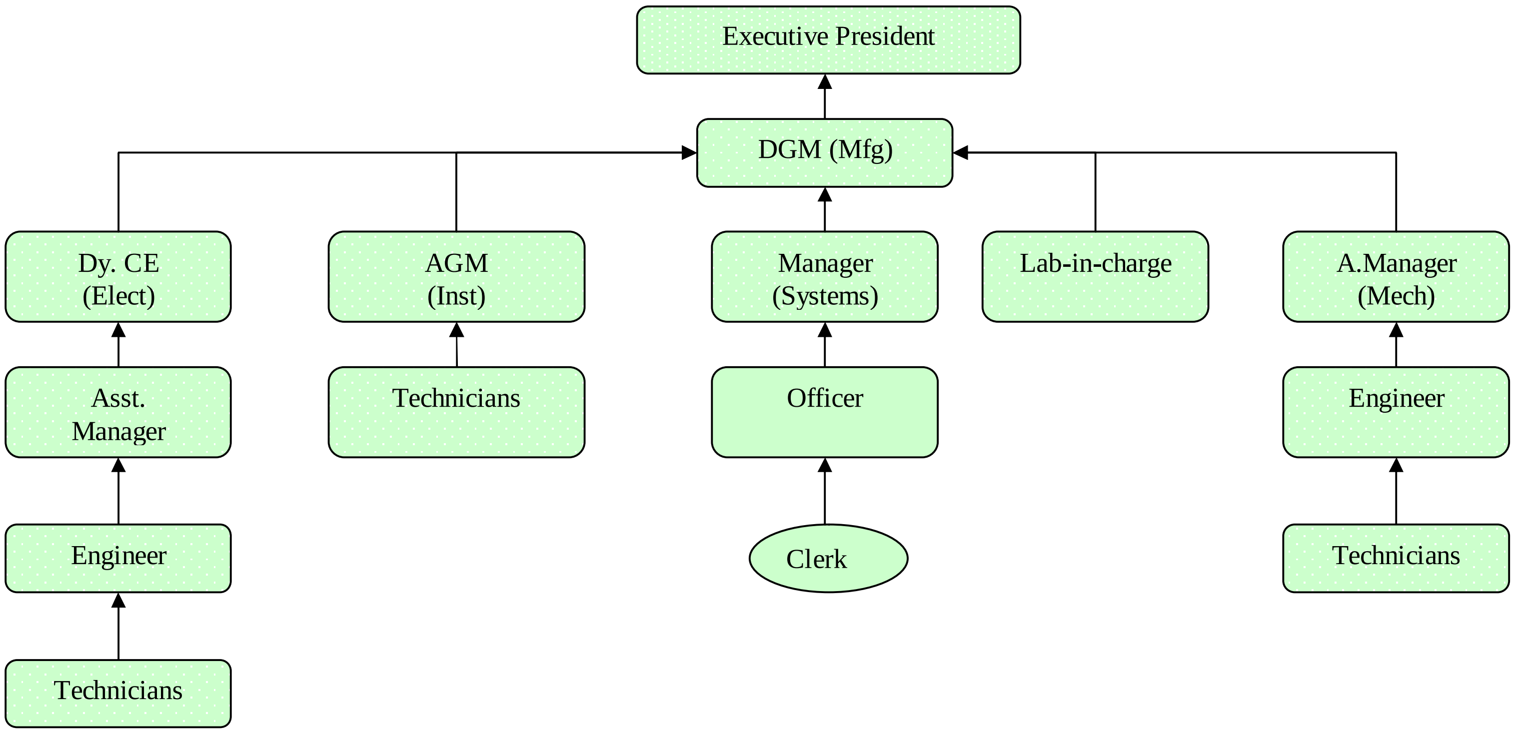
MONITORING INFORMATION

This section elaborates on the monitoring plan to be followed by the project promoters:

CDM TEAM:

The CDM team comprises of personnel from the Engineering, Electrical, Instrumentation, Laboratory and Systems departments. The personnel in the team perform the dual functions of power plant O&M and compliance with CDM procedures. The organization structure of the CDM team is given in Figure 1.

Organization structure showing the CDM Team



Procedures for project performance reviews before data is submitted for internal audit or external verification:

The DGM (Mfg) assisted by the Dy.CE (Electrical) and AM (Mech) would do the project performance review every month based on the monthly energy reports. A comparison of the daily fuel consumption and energy generation data will be done using MS-Excel. This would reveal the performance of the project activity which would be compared against the expected performance levels. Any discrepancy or deviations would be inspected and traced back to original records and corrective action for that parameter as per the CDM Manual would be done.

Procedures for internal audit and Management review:

An internal audit of the project activity would be done on a half yearly basis during the management review meeting (MRM). The review (audit) team would include at least one technical person and an accounts person. The team would audit the project for the below aspects among other things:

- Are the monitoring of CDM parameters done in line with the CDM PDD and CDM Manual
- Is the documentation of monitored CDM parameters done properly
- Are equipments calibrated and maintained as scheduled
- Is the quantity of CERs generated inline with that projected in the CDM PDD? If not, what are the reasons for deviation?
- Are necessary corrective actions being taken to address deviations?
- Check the authenticity of data monitored and recorded by random cross-checking with other sources.

The audit team would submit their observations to the DGM (Mfg) for his review and necessary action. The DGM (Mfg) would instruct the CDM Team to take the required corrective action if any suggested by the audit team.

Procedures for corrective actions for better future monitoring and reporting:

Errors or anomalies in the monitoring and reporting would be identified by the DGM (Mfg) while reviewing the monthly CDM reports. A comparison of these reports would reveal any data errors or missing data or other anomalies. Errors or deviations will also be identified during the half yearly review/internal audits. The DGM would take up these matters during the monthly CDM Team meeting (that normally would happen a few days after monthly CDM reports are prepared and submitted). The root cause of these errors would be discussed and appropriate action would be taken for better future monitoring and reporting. The corrective actions may include:

- Training of monitoring personnel where required
- Replacement or repair of equipment

Procedures for training of monitoring personnel:

- An initial training would be provided by the CDM consultant to all the monitoring personnel identified. Detailed monitoring procedures for each of the CDM parameters would be elaborated.
- Subsequent to the training program, the consultant would witness the actual monitoring on site and help with any difficulties faced by the personnel.
- The DGM would closely inspect the monitoring activities till the mechanism works smoothly.
- Any new person joining the team would be trained on the job by the person being replaced.

Functions of the CDM Team:

- Monitor parameters for calculating emission reductions generated by the project activity
- Maintain records of relevant data for verification of CERs.
- Ensure accuracy of data by proper maintenance and calibration of monitoring equipment.
- Operate the power plant in compliance with the CDM Project Design Document
- Take all preventive measures to ensure plant availability at all times.

CDM Team meeting:

The team meets once a month to review the CDM performance of the plant. Any particular concerns are discussed and appropriate action is taken.

Appendix 1

Abbreviations

BASL	Bannari Amman Sugars Limited
CC	Climate Change
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CER	Certified Emission Reductions
CMIE	Centre for Monitoring Indian Economy
CO	Carbon mono-oxide
CO_2	Carbon di-oxide
CPU	Central Power Units
DCS	Distributed Control System
DPR	Detailed Project Report
DM	De-Mineralised
EGEAS	Electric Generation Expansion Analysis System
EPS	Electric Power Survey
ESP	Electro Static Precipitator
EIA	Environmental Impact Assessment
FD	Forced Draft
FYP	Five Year Plan
GHG	Greenhouse Gas
GOI	Government of India
GWh	Gega Watt hour
HP	High Pressure
HV	High Voltage
ID	Induced Draft
IPCC	Intra-governmental Panel for Climate Change
IPP	Independent Power Producers

IREDA	Indian Renewable Energy Development Agency
ISPLAN	Integrated System Plan
KP	Kyoto Protocol
Km	Kilo meters
KV	Kilo Voltage
KW	Kilo Watt
KWh	Kilo Watt hour
NCES	Non-Conventional Energy Sources
LP	Low Pressure
1 Lakh	1,00,000
MkWh	Million Kilo Watt hour
MU	Million units
MNES	Ministry of Non-conventional Energy Sources
MoP	Ministry of Power
MoU	Memorandum of Understanding
MSW	Municipal Solid Waste
MT	Metric Ton
MW	Mega Watt
NCE	Non Conventional Energy
NEDA	Non conventional Energy Development Agency
Nox	Nitrogen Oxides
NTPC	National Thermal Power Corporation
NOC	No Objection Certificate
p.a	Per annum
PLF	Plant Load Factor
PPA	Power Purchase Agreement
PIN	Project Idea Note
PRDS	Pressure regulating and de-superheating station
REP	Renewable Energy Projects

SA	Secondary Air
SEB	State Electricity Board
SO_2	Sulphur Di-oxide
SPM	Solid Particulate Matter
STG	Steam Turbine Generator
TCD	Tones of Crushing per Day
TDS	Total Dissolved Solids
TERI	Tata Energy Research Institute
TJ	Trillion Joules
TNEB	Tamilnadu Electricity Board
TNPCB	Tamilnadu Pollution Control Board
TPH	Tones Per Hour
UNFCCC	United Nations Framework Convention on Climate Change

Appendix 2

Report on Environmental Impact

The environmental impacts can be either categorized as primary or secondary impacts. Primary impacts are those that can be attributed directly to the project itself while secondary impacts are those, which are induced indirectly because of the development activity which may be triggered by the primary impact. The secondary impacts typically include the associated investment and changed patterns of social and economic activity by the project activity.

The impact of the project on the environment can occur at two stages:

1. Construction phase
2. Operational phase

The project activity concerned has been set up adjacent to the existing sugar manufacturing unit at Sathyamangalam.

Impacts during construction phase

The impacts during construction phase due to the construction of the 20 MW bagasse based cogeneration plant are listed as given here:

Air quality impacts:

- Due to particulate emissions from site clearing
- Due to particulate emissions from quarrying operations offsite
- Due to vehicular emissions from transportation of raw materials such as cement, sand, gravel etc
- Due to particulate emissions from construction activities such as pre-casting, fabrication, welding etc

Noise level increase:

- From earth moving equipments used for site clearing
- From quarrying operations offsite
- From transportation of raw materials such as cement, sand, gravel etc
- From construction activities onsite

Land and soil impacts:

- From change/ replacement of existing land-use by site clearing
- From soil erosion due to removal of vegetation
- From solid wastes disposed on land from construction activities

Water environment impacts

- From consumption of water for construction purposes

Impacts on ecology

- Removal of vegetation at the site

Impacts on socioeconomic environment

- Employment opportunities to local people

The above represents a broad range of environmental impacts that would have occurred during the construction phase of the cogeneration plant.

It should be noted that the impacts due to construction activities are mostly short-term and cease to exist beyond the construction phase.

Impacts during operational phase

The operational phase involves power generation from bagasse. The cogeneration plant feeds surplus power to the grid and indirectly prevents the pollutants otherwise let out into the atmosphere from the thermal power plants (coal, gas and diesel based) of the State grid. Also bagasse being a biomass – renewable fuel does not add any net CO_2 to the atmosphere as the carbon gets recycled during cane growth.

Alternative methods of bagasse disposal being currently practiced in sugar plants includes inefficient burning of bagasse in boilers or letting it to decompose, which would lead to more dust and GHG emissions when compared to the present project activity. The impacts during operational phase of the cogeneration plant are as given here:

Air quality impacts:

The cogeneration plant discharges the following pollutants into the air:

- Suspended Particulate Matter (SPM) from fly ash in the flue gas

- Oxides of Nitrogen (NOx) in the flue gas
- Carbon dioxide (CO_2)

The ash content in bagasse is less than 2%. As the pollution control regulations limit the particulate matter emissions from bagasse fired steam generators to 150 mg/ Nm^3, electrostatic precipitators (ESP's) are used in the cogeneration plant to contain the dust emission from the plant to less than 150mg/Nm^3 during bagasse firing.

The fly ash collected from the ESP hoppers and air heater hoppers and the ash collected from the furnace bottom hoppers are used as landfill during the seasonal operation of the plant when bagasse is the main fuel. Considering the high potash content in the bagasse, the ash is used as manure.

As there is no sulphur in bagasse, SO2 emissions do not occur. The temperatures encountered in the steam generators while burning high moisture bagasse are low enough not to produce nitrogen oxides. Carbon dioxide produced by firing bagasse is absorbed by sugar cane plantation and hence recycled.
To reduce to ground level air contaminants, a 77 m stack is used for baggase-fired boiler. This has helped in faster dispersion of air pollutants into the atmosphere thus reducing the impact on the project surroundings.

During off-season the biomass (cane trash) is transported from nearby cane fields to the project site. However considering 3 truck trips per day for transporting 18 tons/day of cane trash from 50 Km distance, the air emissions are very negligible.

The air emissions i.e. SO2, NOx, CO and SPM emissions released from the stacks attached to the boiler of the cogeneration plant are being monitored as per the Section 21 of the Air (Prevention & Control of) Pollution Act 1981.

Noise level increase:
The sound pressure level generated by the noise sources decrease with increasing distance from the source due to wave divergence. Sound attenuation occurs due to atmospheric effects and its interaction with

objects in the transmission path. As Satyamangalam has lot of trees & greenery the noise levels get attenuated significantly.

In a cogeneration plant, noise level increase is primarily from:

- Cogeneration plant operation
- Transportation of vehicles carrying the biomass i.e. cane trash to the cogeneration power plant.

The rotating equipment of the cogeneration plant is designed to operate with a total noise level which will not exceed 85 – 90 db (A) as per the requirement of the Occupational Health and Safety Administration (OSHA) standards. The rotating equipment is provided with silencers wherever required to meet the noise pollution regulations. As per OSHA, the damage risk criteria enforced to reduce hearing loss stipulates that the noise level upto 90 dBA is acceptable for 8 working hours per day.

The vehicular transport of biomass from nearby cane fields to the cogeneration plant includes only 3 truck trips per day and hence the impact is negligible.

The green belt has been provided around the plant area for noise attenuation. Also the workers are instructed to wear ear masks to reduce noise level impacts.

Water quality impacts:

The effluents generated from the project activity are being treated in the effluent treatment plant to ensure that there is no environmental deterioration.

The wastewater generated from the project activity are as given below:

- Effluent from DM plant: Hydrochloric acid and sodium hydroxide are used as regenerants in the DM water plant for boilers and the acid and alkali effluent are neutralized in an epoxy line neutralizing pits. Generally these effluents are self-neutralizing however, provisions are made such that the effluents are completely neutralized by addition of acid/ alkali. The effluent will then be pumped into the effluent treatment ponds which are a part of the effluent disposal system
- Chlorine in the condenser cooling water is about 0.2 ppm and this value would not result in chemical pollution and meets the national standards for liquid effluent

- The effluent from boiler: The blow down water generated from the boiler would have high pH and temperature from the pollution viewpoint. The effluent is generated at 1.22 TPH having a high pH of 9.8 – 10.3 and temperature of 100 deg C and is disposed into the trench and then through sugar plant effluent ponds
- Sewage from various buildings in the plant are conveyed through separate drains into the septic tank

Wastewater treatment plant has been provided for the adequate treatment of the cogeneration plant effluents. The wastewater is treated to suit its use for irrigation purposes.

The characteristics of effluents from the cogeneration plant are maintained so as to meet the requirements of TNPCB and minimum national standards from thermal power plants.

Ecological impacts:

There are no ecological impacts as the wastewater from the cogeneration plant are treated appropriately before final disposal.

Also as trees have been planted around the plant, it gives a cool atmosphere in the operational area and providse as a barrier for air emissions and noise level increase.

Land and soil impacts:

The solid wastes generated from the cogeneration plant are the dry fly ash and wet bottom ash from Grate. Considering the high potash content in the ash generated from bagasse firing, the same is being used as manure in nearby cane fields. Also since the filter press mud from the sugar plant also has good land nutrient value, ash is mixed with press mud and the same is sold to farmers for use in cane fields.

Socio-economic impacts

The cogeneration plant has contributed to socio economic growth in the following ways;

- Generating employment to 50 technical experts in various fields like mechanical, electrical, electronics, instrumentation, chemical engineering etc
- Feeding of surplus power to the grid thereby bridging the gap between demand and supply in a power deficit State

- Offering environmentally friendly solution for additional power generation without using fossil fuels
- Improving financial position of the sugar plant
- Reducing the fuel transportation costs
- Reducing the transmission losses
- Self reliance of power in rural areas

Environmental Management Plan (EMP)

The EMP is to mitigate and manage the various impacts arising from construction and operational phases of the cogeneration power plant.

<u>Construction phase</u>

Air environment

The following mitigative measures were undertaken during construction phase

- Spraying of water at regular intervals to control fugitive dust emissions from construction activities
- Closing materials in trucks with tarpaulin during transportation of raw materials to the site to prevent dust emissions
- Regular and periodic emission check for transportation vehicles
- Use of personal protective equipment (PPE) like goggles and nose masks to reduce impact of dust emissions during construction activities

Noise environment

- Periodic noise control checks on transportation vehicles
- Provision of ear plugs, work rotation, adequate training

<u>Operational phase</u>

Air environment

- Regular and periodic emission check for transportation vehicles

- Use of personal protective equipment (PPE) like goggles and nose masks to reduce impact of dust emissions
- Periodic monitoring of boiler stack emissions

Noise environment

- Periodic noise control checks on vehicles
- Provision of ear plugs, work rotation, adequate training
- Incorporation of noise control measures at source
- Sound proofing/ glass paneling of critical operating stations
- Regular noise level monitoring at the plant and surrounding area
- Plantation of green belt which acts as a attenuator of noise

Land and soil environment

- Improving the soil quality and plantation of suitable tolerant species in the study area.

Water environment

- Treatment of cogeneration plant effluents in the effluent treatment plant
- Periodic monitoring of water quality parameters

Ecological environment

- Plantation of greenbelt

Socioeconomic Environment

- Training to cane growers and farmers in order to improve productivity

Post project monitoring

- The effluent characteristics are being monitored so as to meet the requirements of the TamilNadu Pollution Control Board under the Section 25/26 of the Water (Prevention & Control of) Pollution Act 1974 and the minimum national standards (MINAS) for effluent from thermal power plants

- Air quality monitoring so as to meet the requirements of the TamilNadu Pollution Control Board under the Section 21 of the Air (Prevention & Control of) Pollution Act 1971
- The air quality parameters being monitored from the stack emissions are SPM and SO_2. A laboratory attached to the cogeneration plant is equipped with necessary instruments for carrying out air quality monitoring.