Voluntary Carbon Standard Project Description

26/10/2009

Version 1.3

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Annexes

1 Description of Project:

1.1 Project title

"20 MW biomass based cogeneration project" at Nelavoy Village, Andhra Pradesh, India
Version 1.3
26/10/2009

1.2 Type/Category of the project

Methodology Details	Description
Type	Consolidated (ACM)
Category	Category 1 – Energy Industries (Renewable/non-renewable sources) *Methodology Details:* Approved consolidated baseline and monitoring methodology ACM0006 : "Consolidated methodology for electricity generation from biomass residues" (Version 8 dated 25 March 2009)
Reference	http://cdm.unfccc.int/UserManagement/FileStorage/C4XJL50NM9UF6KPO7YGZIV3DBAW1T8

- The project category is a part of the Clean Development Mechanism (CDM) that has been approved by VCS board.
- The proposed project is not a grouped project.

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

Project Size:

The project activity is a biomass based cogeneration plant of capacity 20 MW. According to the VCS program guidelines paragraph 5.1, the project activity falls under the "projects" group whose estimated emissions reductions are between 5,000 and 1,000,000 tCO_2e per year. The implementation of this project activity is expected to result in an annual emission reduction of 34,019 tonnes CO_2 equivalent emissions per year over the crediting period.

Year	Estimate of GHG abatement (in tCO_2e)
2008	34,019
2009	34,019
2010	34,019
2011	34,019
2012	34,019
2013	34,019
2014	34,019
2015	34,019

2016	34,019
2017	34,019
Total emission reductions (tCO_2e)	3,40,190
Total number of crediting periods	Ten years
Annual average over the crediting period of emission reductions (tCO_2e)	34,019

1.4 A brief description of the project:

The primary objective of the project is to

- ***Implement a high efficiency biomass residue based cogeneration project at a green field sugar plant and export the surplus electricity to grid.***

Sagar Sugars and Allied Products Limited (SSAPL) is a public limited company incorporated as a subsidiary of Mohan Breweries and Distilleries Limited (MBDL), one amongst successful business units in India with a number of other companies in its fold. SSAPL has come up with a green field sugar manufacturing plant at Nelavoy Village, Andhra Pradesh. A new cogeneration project activity has been implemented along with it to effectively utilize the bagasse generated in-house. The cogeneration plant has been designed to utilize the surplus bagasse from the sugar plant efficiently and generate electricity in excess of the captive requirements, against the business as usual practice of installing a lower efficiency cogeneration plant. The surplus electricity is exported to the grid and replaces equivalent electricity from emission intensive grid sources. The cogeneration plant is rated for a nominal output of 20 MW and would operate for around 350 days in a year exporting surplus electricity to the Southern Power Distribution Company of Andhra Pradesh Limited (APSPDCL) grid.

The technical details of the project activity are given in the table as follows:

Description	**Data**	**Unit**
Cane crushing capacity	2500	TCD
Hourly crushing capacity	113.64	TPH
Average bagasse % on cane	30	%
No of days of cogeneration plant operation - Cane crushing season - Off-season	 180 170	 days days
Plant Load Factor (PLF)	80	%

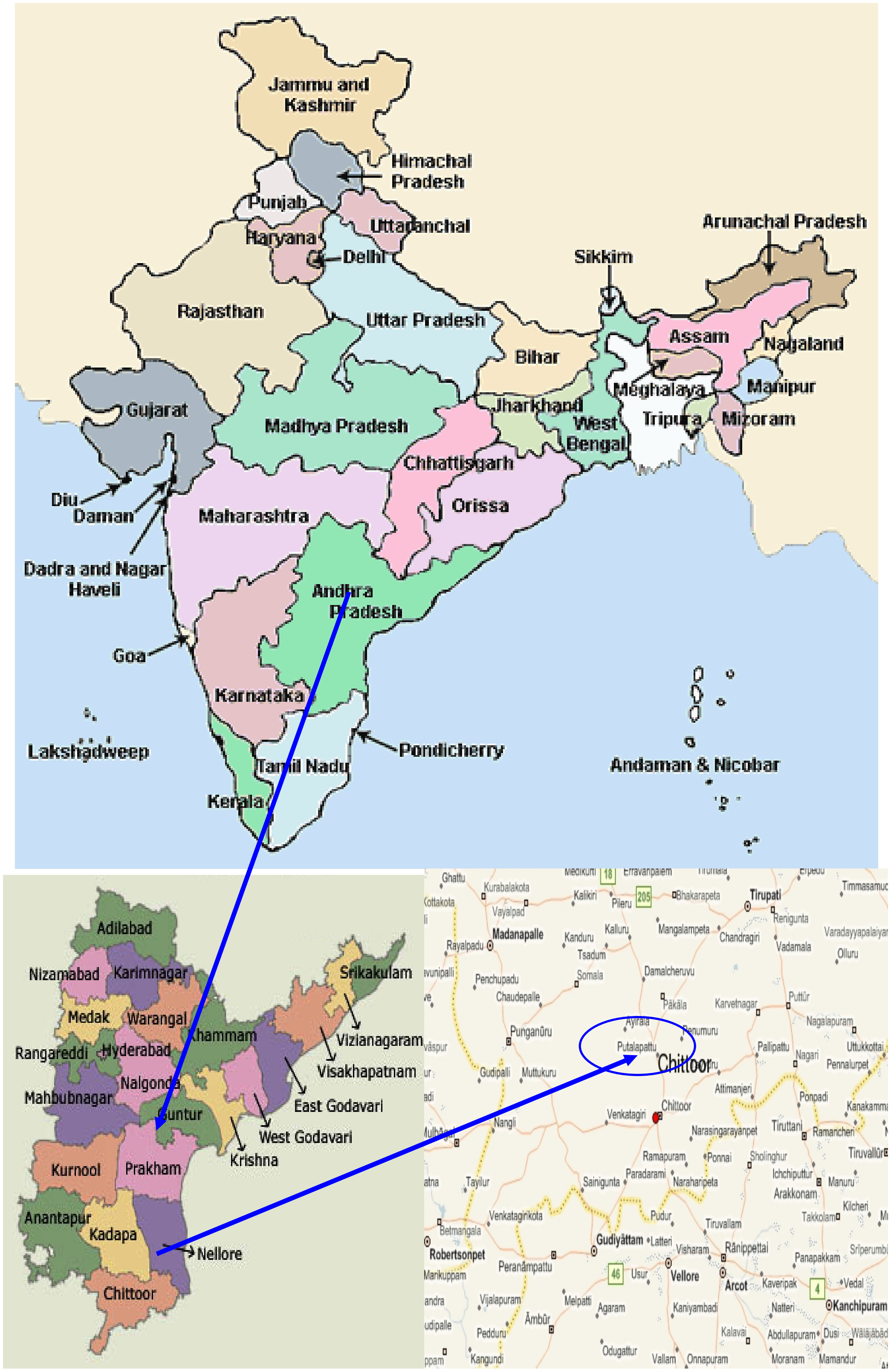
Description	Season	Off-Season	Unit
Total installed capacity	20.0	20.0	MW
Gross power generation	14.89	19.24	MW
Cogeneration plant power consumption	1.70	2.10	MW
Net power generation	13.19	17.14	MW
Power to sugar plant	3.20	0.20	MW
Net power export	9.99	16.94	MW
Gross power generation	51459.8	62799.6	MWh
Auxiliary power consumption	5875.20	6854.40	MWh
Net power generation	45584.6	55944.9	MWh
Fuel type	Bagasse	Purchased bagasse	
Captive bagasse available (wet)	33.21	--	tph
Bagasse/biomass consumed for cogen	33.21	33.21	Tph
Surplus bagasse	0	0	Tonnes
Net Calorific value	3600	3600	Kcal/kg
Total Bagasse/Biomass consumed (wet basis)	114768	108392	T/year

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

Description	Details
Location	Nelavoy village, Sri Rangarajapuram Mandal, Chittoor District in Andhra Pradesh
Latitude	13° 19.5’N
Longitude	79° 23.0’E
Nearest railway station	Chittoor which is 40kms away from the project site

The geographical location of the project activity is shown in the map given as follows[1]:

[1] http://im.sify.com/news_info/weather/images/map.gif
http://www.altiusdirectory.com/Society/images/political_map_of_andhra_pradesh-1.jpg
http://www.weather-forecast.com/locations/Chittoor



1.6 Duration of the project activity/crediting period:

Description	Details
Project Start date	13/01/2003 *Date on which project is synchronized with Southern Power Distribution Company of Andhra Pradesh Limited (APSPDCL) grid for commercial operation.*
Crediting period start date	*01/01/2008*
Crediting period end date	31/12/2017

1.7 Conditions prior to project initiation:

The proposed project activity is a green field co-generation plant installed along with a green field sugar manufacturing plant. Hence, there was no activity happening prior to project initiation.

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

A high efficiency co-generation plant which has been designed to utilize the surplus bagasse from the sugar plant efficiently is employed in the project activity against a business as usual case of installing a lower efficiency co-generation plant. The surplus electricity generated from the project activity is exported to the grid which would displace equivalent electricity (which would had been generated from an emission intensive grid sources) and reduces its equivalent GHG emissions. The emission reductions due to displacement of heat is assumed to be zero for this project activity, the justification of the same is presented in section 4.1.3.

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

The project activity involves electricity generation by direct-firing of biomass in the power plant. The biomass fuel is burned in a boiler to produce high-pressure steam. The steam is introduced into a steam turbine, where it flows over a series of aerodynamic turbine blades causing the turbine to rotate. The turbine is connected to an electric generator to convert the rotational energy into electricity. The electricity generated is used to cater the energy demands of the sugar factory and the surplus is sold to the APSPDCL. The technical details of the major equipments are given as follows

Technical Details of Boiler

Particulars	Units	Parameters
Steam output	TPH	80
Steam outlet pressure	ata	67

Steam outlet temperature	^{o}C	485$\pm$5

Technical Details of Turbo Generator

Particulars	Units	Parameters
Capacity	MW	1 X 20
Steam pressure at the inlet to turbine	ata	64
Steam temperature at inlet to turbine	^{o}C	480
Type	Cogeneration mode – Double extraction cum condensing type	

Power Evacuation

The power generated at the generator is at 11 kV which is stepped up to 132 kV for export to the grid. Power for captive consumption is drawn after stepping it down to 440 V.

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

SSAPL is in compliance with all the relevant local rules and regulations[2] as prescribed by Ministry of Environment & Forest (MoEF), Government of India (Host Party) and has prepared the following documents:

- Environment Clearance to operate the plant in the form of "Consent to Operate" from the Andhra Pradesh Pollution Control Board (APPCB).
- Environment Impact Assessment (EIA) and Environment Management Plans (EMPs) have been prepared and submitted to Pollution Control Board (PCB)
- "Consent to Operate" obtained from APPCB under section 25/26 of the Water (Prevention and Control of Pollution) Act, 1974 and its subsequent amendments
- "Consent to Operate" obtained from APPCB under section 21 of the Air (Prevention and Control of Pollution) Act, 1981 and its subsequent amendments

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

[2] The regulations include Electricity (Supply) Act, 1948 and regulations of the Andhra Pradesh Electricity Regulatory Commission (APERC) which were applicable during the start of the project activity. At present, "The Electricity Act, 2003" enacted by Government of India on June 10, 2003 has repealed the three acts which were in existence namely i) The Indian Electricity Act 1910 (ii) The Electricity (Supply) Act, 1948 and (iii) The Electricity Regulatory Commissions Act, 1998. The Electricity Act, 2003 was enacted to harmonize and rationalize the provisions in the existing laws in India; it consolidated the laws relating to generation, transmission, distribution, trading and use of electricity

The project activity uses biomass residues (own plant bagasse during crushing season and other purchased biomass residues during off season) as the primary fuel and may be supplemented with minor quantities of fossil-fuels for stable operation during situations like high moisture content in bagasse, non-availability of primary fuel etc. The usage of fossil fuel to cater the energy source during the situations as mentioned above would affect the GHG emission reductions from the project activity. The risks that may substantially affect the project's implementation are briefed in section 2.5 under step – 2 (barrier analysis).

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

The proposed project is a high efficiency biomass residue based cogeneration project implemented at a green field sugar plant primarily aimed to reduce GHG emissions and to contribute to sustainable development. The project activity was not implemented to create GHG emissions for the purpose of its subsequent removal.

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

The project has not created any other form of environmental credit for the same crediting period as for the VCS program; the project claims VCUs for the crediting period of the project activity and does not yield any other emission certificates other than VCUs.

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

SSAPL has not undergone any other GHG emission programmes. SSL is applying for VCS programme to avail carbon benefits during the crediting period of the project activity.

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

Organization:	Sagar Sugars and Allied Products Limited
Street/P.O.Box:	158, Anna Salai
Building:	Rayala Towers II Floor
City:	Chennai
State/Region:	Tamil Nadu
Postfix/ZIP:	600 002
Country:	India
Telephone:	044 – 28420325
FAX:	044 – 28521266
E-Mail:	ssapl@mbdl.co.in
URL:	www.mbdl.co.in

Represented by:	
Title:	Executive Director
Salutation:	Mr.
Last Name:	Nandagopal
Middle Name:	
First Name:	Arvind
Department:	
Mobile:	-
Direct FAX:	
Direct tel:	
Personal E-Mail:	

SSAPL would be the project participant, and all communication with the validator and/or verifier as well as with the VCS registry would be the entity listed in the table above.

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

The project has contributed to sustainable, social, economic, technological and environmental development in many ways as listed below:

Economic:

The project activity supplies a considerable quantity of electricity to the local grid thereby improving the regional power availability and power quality. The improved power situation could facilitate economic development in the region.

Social:

The improved power supply quality as a result of the project activity helps to improve the overall quality of life in the region.

Technological:

At the time of conceptualisation of the project activity, the high pressure (67 ata) cogeneration technology was not prevalent in the region. SSAPL adopted this advanced technology and therefore has demonstrated its feasibility to similar project promoters in the region.

Environmental:

The project activity uses clean and environmentally neutral fuel (biomass residues) for energy generation which is supplied to the grid. An equivalent quantity of fossil fuel is conserved resulting in the reduction of carbon dioxide emissions associated with its combustion. Moreover, the project also reduces the release of noxious emissions into the air which is involved in fossil fuel combustion.

1.17 List of commercially sensitive information (if applicable):

Not applicable.

2 VCS Methodology:

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

Methodology Details	Description
Methodology Title	Consolidated methodology for electricity generation from biomass residues
Scale	Large Scale – Consolidated
Sectoral Scope:	1 – Energy Industries (renewable -/ non –renewable sources)
Version No	8
References	The methodology refers to the latest approved version of the followings 1. ACM0002 ("Consolidated baseline methodology for grid-connected electricity generation from renewable sources") 2. Combined tool to identify the baseline scenario and demonstrate additionality 3. Tool to calculate baseline, project and/or leakage emissions from electricity consumption 4. Tool to calculate project or leakage CO2 emissions from fossil fuel combustion 5. Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site
Weblink	http://cdm.unfccc.int/methodologies/DB/21340DWSMIAU27O7K6VSYQMXMUBK80/view.html

The explanation of methodology choice is described in section 3.1.

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

Among the methodologies approved by UNFCCC for biomass based CDM project activities, ACM0006 (version 08) has been chosen as most suitable to this project activity. The project activity meets the applicability conditions of ACM0006 version 08, as demonstrated below

Conditions of ACM0006	Applicability to project activity
Applicable to biomass residue fired electricity generation project activities including cogeneration plants	The project activity involves biomass residue (bagasse) fired cogeneration with export of power to the APTRANSCO grid.
The installation of a new biomass residue fired power	Project activity is a green field co-generation project

plant at a site where currently no power generation occurs Greenfield power projects)	installed along with a green field sugar manufacturing plant.
May be based on the operation of a power generation unit located in an agro-industrial plant generating the biomass residues.	The project activity is located in a sugar plant and is based on the biomass residue (bagasse) generated in the sugar plant. Other purchased biomass residues may also be used during non-availability of bagasse.
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 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).	The project activity uses bagasse as the main fuel and may be supplemented with minor quantities of fossil-fuels for stable operation during situations like high moisture content in bagasse, non-availability of fuel etc.
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;	The cogeneration project activity does not result in any capacity increase or process change of the sugar plant.
The biomass used by the project facility should not be stored for more than one year.	Bagasse is stored temporarily for a period of only 6-8 months.
No significant energy quantities, except from transportation of the biomass, are required to prepare the biomass residues for fuel combustion,	No significant energy quantities are required for fuel preparation.
The methodology is only applicable for the 22 combinations of project activities and baseline scenarios identified in the	Project activity falls under scenario 4.

methodology.	

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

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

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 version 08. The project boundary includes the following emission sources:

	Source	Gas		Justification/Explanation
Baseline Scenario	Grid 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 in Onsite boilers	CO_2	Included	Main Emission source.
		CH_4	Excluded	Excluded for simplification. This is conservative.
		N_2O	Excluded	Excluded for simplification. This is conservative.
	Decay or uncontrolled burning of surplus biomass residues	CO_2	Excluded	No surplus biomass residues
		CH_4	Excluded	No surplus biomass residues
		N_2O	Excluded	No surplus biomass residues
Project Scenario	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	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 CO2 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 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 CO2 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 is 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 treatment of biomass residues	CO_2	Excluded	It is assumed that CO2 emissions from surplus biomass residues do not lead to changes of carbon pools in the LULUCF sector.
		CH_4	Excluded	There is no waste water generated from treatment of biomass residues.
		N_2O	Excluded	Excluded for simplification. This quantity is very small.

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

As prescribed by ACM0006 version 08, 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.

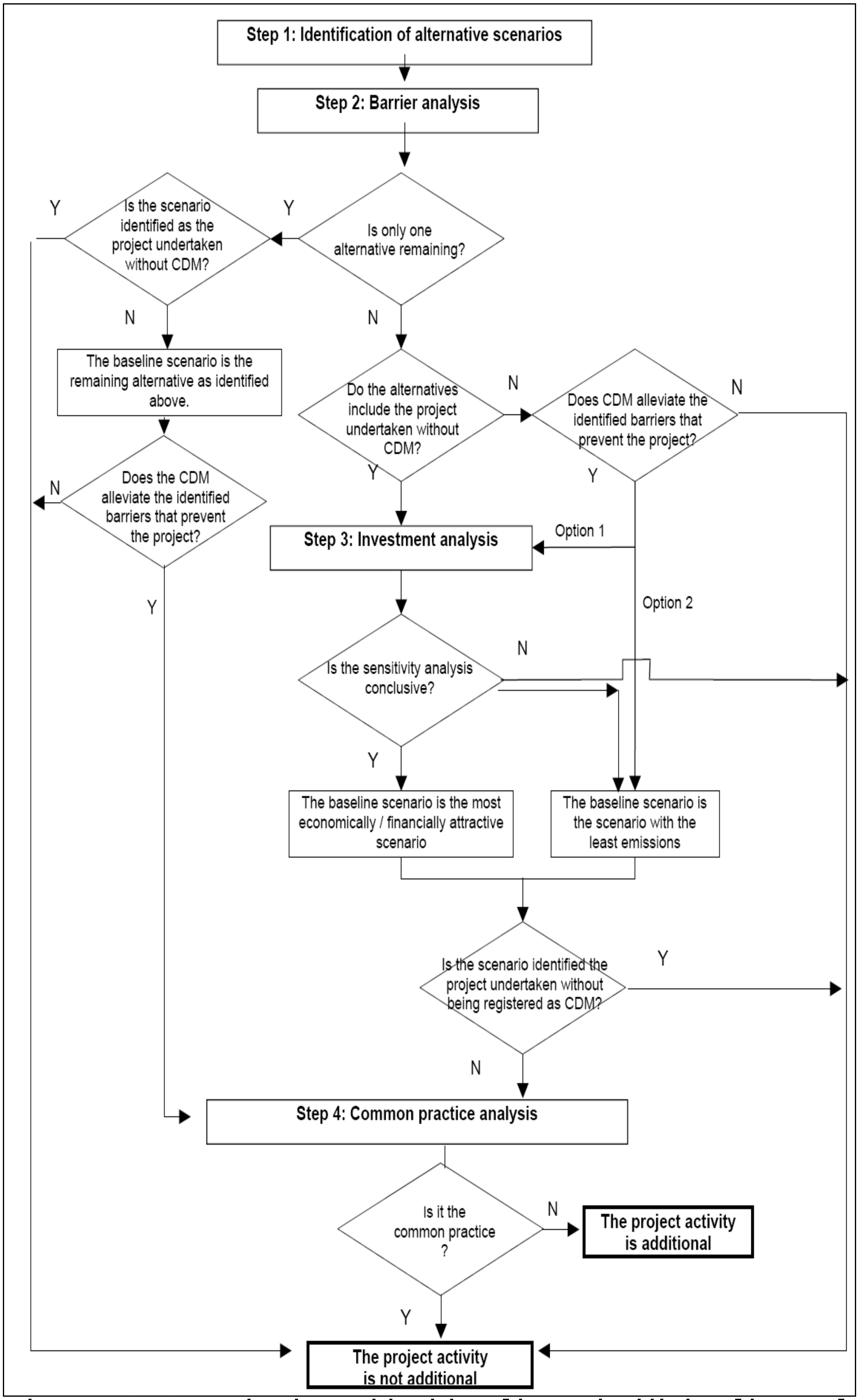


Figure B.2: Steps in the combined baseline and additionality tool

In applying step 1 of the tool, project participants have determined the most plausible baseline scenario among all realistic and credible alternatives separately regarding:

- How power would be generated in the absence of the VCS project activity
- What would happen to the biomass in the absence of the project activity
- In case of cogeneration projects: how heat would be generated in the absence of the project activity

STEP 1: IDENTIFICATION OF ALTERNATIVE SCENARIOS

Sub-step 1a. Define alternative scenarios to the project activity

The various alternatives to the project activity are being identified in this section separately for power, heat and biomass. The main criteria for identifying the alternatives are that they should be able to deliver services and output equivalent to that of the project activity (i.e., the alternatives should be able to; generate the same quantity of power and steam, and consume as much biomass residues as that of the project plant)

Alternatives available for power generation:

P1 The proposed project activity not undertaken as a VCS 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 not an alternative to power generation since there are no existing power plants at the site. Therefore, this alternative is not considered further.

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 are no fossil fuel based power plants 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 Indian 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 a stand alone alternative; rather, it would be combined with other alternatives.*

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 scenario for the power generated in the project activity. 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).

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. The normal practice of sugar mills in the region is to install sufficient cogeneration capacity to utilize the in-house bagasse generated during the season. During off-season, an equivalent quantity of other purchased biomass residues would be used for power generation. 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 not an alternative to power generation since there are no existing power plants at the site. 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 not an alternative to power generation since there are no existing power plants at the site. 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 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 a captive fossil fuel power plant at the site. However, this is not a credible option since bagasse is a freely available by-product and bagasse based cogeneration is an essential aspect in Indian sugar mills for economical operation. It would be an economical option for SSAPL to use the freely available bagasse for cogeneration rather than purchasing fossil fuel at an additional cost.

Alternatives available for heat (process steam) generation:

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

This is a possible alternative 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 alternative to the heat generated in the project activity. In this case, since the proposed project activity is installation of a green field cogeneration power plant, the heat (process steam) required for power generation in the project activity would have been generated by firing the same type of biomass residues as used in the project activity but with a different efficiency of heat generation that is common in practice in the sugar manufacturing plant.

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

This is a not a credible alternative 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 alternative 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 not a credible alternative to the heat generated in the project activity as there are no cogeneration plants existing in the project site prior to implementation of the project activity.

H6 The generation of heat in boilers using fossil fuels

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. 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 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. 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.

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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its 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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its 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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its 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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its 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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its energy requirements. Therefore, this alternative is not considered further.

B7 The biomass residues are used for other energy purposes, such as the generation of bio-fuels.

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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its 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. SSAPL would require the biomass residues for combustion in a cogeneration plant to meet its 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, P4 and P5***
- ***Identified credible alternatives for heat generation are H1 and H2***
- ***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 08.

Baseline option 1 (BA1):

- Installation of a bagasse based cogeneration system with an efficiency that is common practice in the sugar mill sector of the region (i.e., with 43 ata operating pressure). The thermal firing capacity will be same as that of the project activity. Since the operating pressure of this system (43 ata) is lower than that of the project plant (67 ata), the electrical efficiency is also lower than the project plant.

- The same type and quantity of biomass residues as in the project plant would be used in the low efficiency system.
- The power generation in this system will be lower than that of the project plant since the same quantity of biomass residues are used at a lower efficiency.
- The surplus power after meeting the captive requirements would be exported to the grid. However, the quantity of power exported would be lower than that of the project activity.
- The plant would generate the same quantity of heat as that of the project plant.
- This alternative is a combination of options P4,P5,H2 and B4. As per these baseline power, heat and biomass options, this baseline option falls under scenario 4 of ACM0006 version 08.

Baseline option 2 (BA2):

- Implementation of project activity not undertaken as a VCS project activity

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

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

- The applicable regulations [3] do not restrict SSAPL to generate steam and power using the lower efficiency lower pressure (43 ata) system or in a high efficiency (67 ata) system
- The applicable regulations do not restrict SSAPL to generate steam and power from bagasse or other biomass.
- Though the Ministry of Non-Conventional Energy Sources (MNES) aims to achieve 10% of installed power generation capacity from renewable sources, there is no mandate on any private entity to enhance power generation capacity from renewable sources.

Both alternatives BA1 and BA2 are in compliance with mandatory legislation and regulations.

[3] The regulations include Electricity (Supply) Act, 1948 and regulations of the Andhra Pradesh Electricity Regulatory Commission (APERC) which were applicable during the start of the project activity. At present, "The Electricity Act, 2003" enacted by Government of India on June 10, 2003 has repealed the three acts which were in existen ce namely i) The Indian Electricity Act 1910 (ii) The Electricity (Supply) Act, 1948 and (iii) The Electricity Regulatory Commissions Act, 1998. The Electricity Act, 2003 was enacted to harmonize and rationalize the provisions in the existing laws in India; it consolidated the laws relating to generation, transmission, distribution, trading and use of electricity.

The next step of the “Combined tool to identify baseline and demonstrate additionality” is “Barrier Analysis”. This is continued in the following section (2.5) of the PD.

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

In order to demonstrate that the VCS project activity reduces anthropogenic GHG emissions that would have occurred in the absence of the project activity, it is necessary to prove that:

- The implementation of the project activity is not the baseline scenario, (i.e., under normal circumstances, there would be not be a high pressure high efficiency cogeneration plant and thereby SSAPL would export lesser power to the grid).

ACM0006 version 08 prescribes the use of the “Combined tool to identify the baseline scenario and demonstrate additionality” (Figure B.2 in section 2.4 above) for the above purpose, which is applied to the project activity. The step 1 of the tool is applied in section 2.4 above and the subsequent steps are applied below:

STEP 2 - BARRIER ANALYSIS

Sub-step 2a. List of barriers that may prevent one or more alternative scenarios to occur

SSAPL conceptualised the green field sugar plant project at Chittoor and its construction started in the year 2000. To meet the sugar factory’s energy requirements and utilise the bagasse generated, a cogeneration plant was planned as was common practice in the Indian sugar industry. During this period, SSAPL realised, through various industry sources, the potential of additional power generation from its cogeneration plant through adoption of high pressure (67 ata) high efficiency cogeneration technology. This opportunity was explored and the promoters observed that the proposal involved additional investment outlay, the returns of which were sensitive to technological, tariff policy, climatic and other risks, and therefore were sceptical in implementing the proposal. The barriers encountered by SSAPL in its decision to implement the project activity are as follows:

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[4]. MNES has appointed nodal agencies to represent it in each of the states. Further, MNES has published the list of co-generation plants commissioned till year 2003. The list of Cogeneration plants operating/planned at the time of investment decision of the project activity is presented below based on the SISMA[5] (The south Indian Sugar mill Association) letter provided to the project proponent.

S.N	Name	Installed Capacity	Date of construction start[6]	Commissioning date[7]	Boiler Pressure (in ata)
1.	The Andhra Sugars Ltd	7.0	May 1997	21/01/1999	44
2.	Deccan Sugars	7.0	June 1997	07/02/1999	42
3.	Sudalagunta Sugars Ltd	8.0	November 1997	12/06/1999	42
4.	Gayatri Sugars Ltd	9.0	October 1999	01/05/2001	41
5.	GMR Industries Limited	16.0	October 1999	15/08/2001	45
8.	***Sagar Sugars & Allied Projects Limited***	***20.0***	***January 2000[8]***	***13/01/2003***	***67 (Project Activity)***
6.	Kakatiya Cment Sugar & In. Ltd	17.0	October 2000[9]	12/04/2002	85 (After project start date)
7.	Ganpati Sugar Indus. Ltd.	15.0	May 2001[10]	01/01/2003	66 (After project start date)
9.	The Jeypore Sugar Co; Ltd.	13.5	March 2002	05/11/2003	62 (After project start date)

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

[5] Letter from "The South Indian Sugar Mills Association – Andhra Pradesh."

6 This is arrived based on subtracting the gestation period for co-generation plants of 20 months, from the date of commissioning. http://www.carensa.net/PDF/Sugarcane%20Bagasse%20Cogeneration%20as%20a%20Renewable%20Energy%20Resource%20for%20Southern%20Africa_17Jun07.pdf

[7] Letter from "The South Indian Sugar Mills Association – Andhra Pradesh."

[8] Date of Notification of Award for Turbo Generator package service dated 19.01.2000

9 Project being completed in a record period of 18 months, copy of the MNES document being submitted to DOE http://mnes.nic.in/annualreport/2002_2003_English/ch5_pg14.htm

10 This project has got registered under Clean Development Mechanism (CDM) (http://cdm.unfccc.int/Projects/DB/SGS-UKL1146080365.67/view)

It may be noted from the above table that there were no plants with 67 ATA high pressure technology operating/planned in the state of Andhra Pradesh, during conceptualization of this project activity (in March 2000). 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 67 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.

Type of barrier	***Technological barrier –Risks involved in high pressure cogeneration system and availability of skilled manpower.***
Cause	At the time of conceptualisation of the project activity (year 2000), there were very few sugar mills in the region with a high pressure grid connected cogeneration system. According to an MNES report[11], at the time of conceptualisation of project activity in year 2000, only three sugar plants in the state of Andhra Pradesh had grid connected co-generation plant exporting power to the APTRANSCO grid with the maximum capacity export quantity being 4.5 MW. In 2000-01, 5 more plants were commissioned all with export capacity less than that of the project activity *(Please refer to the section "first of its kind in the region" presented above this table).* At the time of implementation, the boiler capacity of 67 ata and generating capacity of 20 MW was a pioneering effort in the state of Andhra Pradesh and was one among the first few in the country. Out of the total potential for bagasse cogeneration in Andhra Pradesh of 200 MW, installed capacity was 35 MW in 2000-01. At the time of start of project activity the technology employed was a pioneering attempt since all other similar plants had boiler pressure of around 42 ata *(Please refer to the section "first of its kind in the region" presented above this table)*. Thus the high pressure cogeneration technology was not yet established in the region and therefore there were uncertainties regarding the performance and life of the technology. As a result of the low prevalence of the technology, skilled and experienced manpower to operate such systems would also be not available. These proved as significant barriers to SSAPL.
Description	• ***Performance uncertainties:*** The design, construction and operation of a

[11] MNES document being submitted to DOE

	high pressure cogeneration system are significantly different from that of a low pressure system. At high operating pressures, boiler metallurgy (the ability to withstand thermal and mechanical stress) and water chemistry assume critical importance. The sustained performance and operational life of a cogeneration power plant depends on various factors like thermal stress pattern (cyclical loading), quality of water, steam parameters, cooling water parameters and proper operation and maintenance. The basic principle used in a low pressure cogeneration system and a high pressure system is the same – the Rankine cycle. However, the design, construction and operation of a high pressure system are more complicated and significantly different than that of a low pressure system. As the operating pressure increases, the monitoring and control of water/steam parameters is of critical importance. Even minor fluctuations in water/steam properties could cause dramatic effects on the performance and life of the boiler and TG. The boiler materials have to be designed to withstand the thermal stress expected as a result of high temperature and pressure differentials. Following are the critical factors of importance in high pressure cogeneration technology as stated by Avant-Garde Engineers and Consultants Pvt. Ltd. (AG), renowned consultants in the Indian Cogeneration sector. • ***Water quality management – silica carryover*** At higher operating pressures, maintaining proper feed water quality is of paramount importance. AG's technical paper states as follows[12]: "This is one area that needs more attention. Extraction steam at low pressures is supplied to the sugar plant for processing. About 90% of the steam supplied to the sugar processing is returned as condensate to the steam generator feed water system, at a temperature of around 95 Deg.C. Generally there could be no contamination of this condensate. Sincere and disciplined efforts should be made to keep this condensate free from contamination. We are not recommending the usage of the vapor condensate

[12] Copy of the third party evidence being submitted to DOE

	for the feed water application as the quality of this condensate varies. Generally the pH is low, the TDS and silica are high and there could be traces of ammonia and organic compounds. We could use this with a lot of monitoring, but the repercussions could be serious if the monitoring system malfunctions or fails. This aspect of water management needs some more study and a lot more of discipline." • ***Lack of spares and servicing network:*** The high pressure technology being in its nascent stages and 67 ATA system being the first of its kind in the region, we were particularly concerned with the availability of suitable spare parts and experienced servicing manpower. AG's technical paper states as follows[13]: "The major issues in adopting higher pressure cycles are the selection / availability of proven high capacity boilers and fuel handling / firing system. The availability of servicing facility and spares for imported high capacity turbo generators could also be a specific problem." "However there is a specific problem with regard to the servicing and spares availability. There are a number of suppliers who can supply the machines, but other than One or Two, there is none that has set up an adequately staffed service network and stocks adequate spares. This could pose major problems, specifically after the warranty periods. Most of the suppliers, import the turbine steam path components, generators, AVRs and a few auxiliary equipment, and in such cases spares and servicing could pose serious problems." Thus it can be seen that a high pressure system is more sensitive to these factors than a low pressure system thus increasing the risk of performance loss and equipment damage. Any performance loss or frequent maintenance shutdowns would correspondingly reduce the power and steam output. SSAPL was wary that such a situation would not only impact the energy sale revenue but also affect the primary manufacturing process (The sugar plant depends on the cogeneration system for its power and steam requirements. In case the high pressure

[13] Copy of the third party evidence being submitted to DOE

	cogeneration system has to be shutdown, the sugar plant would also be shut down resulting in huge financial loss). Thus SSAPL was apprehensive of implementing a technology that not only risks the economic feasibility of the project activity but also that of the primary business. • ***Lack of trained manpower:*** As stated above, metallurgy and water chemistry are critical parameters in high pressure cogeneration systems. Minor deviations in the operating parameters could result in reduced equipment life, loss of performance and unscheduled maintenance shutdown. Therefore the Operation and Maintenance (O&M) of high pressure system is complicated and requires frequent monitoring and control of critical parameters which is possible only with a trained and experienced O&M team. The low prevalence of high pressure systems in the region also meant a limited availability of skilled manpower to operate such systems. SSAPL was apprehensive of this lack of experienced and trained manpower that could transform into unscheduled shutdowns, performance loss or degradation of equipment life.
Likely Impacts	• Less than expected performance • Loss of production as a result of unscheduled shutdowns and reduced performance • Equipment damages and failures
Effects	• Lower profitability • Higher maintenance cost

Type of barrier	***Uncertainty in the power purchase tariff***
Cause	Dynamic policy and regulatory scenario in the state
Description	At the time of conceptualisation of the project activity (year 2000), the electricity regulatory scenario in the state of Andhra Pradesh (AP) was very dynamic and liable to change. • During year 1997, the AP government order stipulated a uniform purchase tariff for electricity purchase from non-conventional energy sources. However, this purchase tariff was applicable only till the year 2000 beyond which there were uncertainties in the purchase tariff

	• The above order was further amended in year 1998. • The AP Electricity Reform Act (APER Act) came into force on 01.02.99 • The AP Electricity Regulatory Commission (APERC) was constituted on 03.04.1999 as per the APER Act with the aim of rationalising the power scenario in the state. • The project was conceptualised during this period (1999-2000) of high uncertainty. With the existing power purchase policy expiring in year 2000, it was likely that a revised tariff was fixed by the newly appointed APERC. • SSAPL was apprehensive of implementing the project activity, which is mainly dependent on the power sale revenues, during this period of dynamic regulatory scenario.
Impacts	Any downward revision of the purchase tariff or other negative policy changes will have a serious negative impact on the project returns forcing the project into financial bankruptcy. In fact, SSAPL's apprehension was realised in March 2004[14] when there was a negative revision of the power purchase tariff by APERC. The PPA signed by SSAPL with APTRANSCO on 10.07.2002, offered a purchase tariff of Rs.3.48 per kWh for 2003-04. However, the PPA stated that the tariff was applicable only till April 2004, beyond which a revised tariff as fixed by the APERC shall be applicable. In March 2004, apart from lowering the power purchase tariff for bagasse cogeneration plants, APERC also limited the Plant Load Factor (PLF) to 55%, energy exports will be paid only with variable cost and an additional incentive as indicated in the APERC order dated March 20, 2004 [15] for every unit delivered in excess of 55 % which is lower than the power purchase tariff for plants operating below 55 %. The project activity has been since operating at around 55% PLF with low capacity utilisation. This twin revision would result in huge financial losses to the project activity and the realised returns would be much lower

14 APERC Tariff order

a. http://www.ercap.org/OtherOrders/Orders.html

b. http://www.ercap.org/TariffOrders/TO_2004-05_highlights.html

c. http://www.ercap.org/TariffOrders/TO_2004-05.pdf

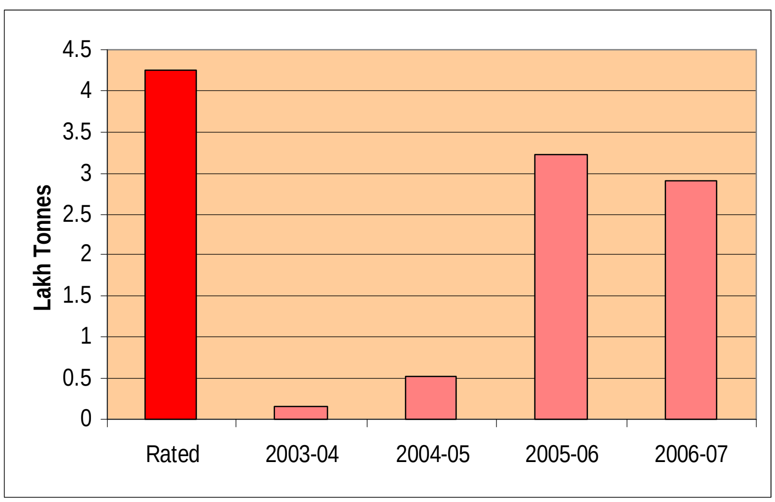
15 http://www.aperc.gov.in/OtherOrders/Order_RP_84_2003.doc

	than the expected returns. The continuation of this situation would make a significant portion of the project as an idle investment as the power plant would continue operating only at 55% PLF. The inflow of VCS revenues as additional revenue could help the promoters to operate the plant at higher PLF. In addition, though SSAPL was eligible for a purchase tariff of Rs.3.11 per kWh, the DISCOM has been paying only at Rs.2.69 per kWh citing ambiguities in the APERC order resulting in huge amounts pending as arrears. After a prolonged litigation, SSAPL has successfully obtained approval for the arrears payable to it. Thus, the risk of tariff policy uncertainty considered by SSAPL is real.
Effects	Lower revenue realisation resulting in poor or negative profitability, difficulty in servicing loans and cash flow problems.

Type of barrier	***Uncertainty in fuel availability***
Cause	Fluctuations in climatic conditions and rainfall pattern. Occurrence of drought conditions. Incidences of crop disease and other factors affecting sugar cane growth.
Des-cription	The planned fuel sources for the project activity were captive bagasse during the crushing season and purchased external biomass residues during the off-season. The availability of bagasse and biomass are in turn directly dependent on the regional agricultural output. The region surrounding the project activity is prone to drought and frequent fluctuations[16] in the annual rainfall pattern. Crop diseases and pests also significantly reduce agricultural output during some years. SSAPL was apprehensive about this major factor that could negatively impact the project activity. The quantum of power exported is directly dependent on the cane availability since bagasse is used as the primary fuel. SSAPL's sugar plant was being setup as a green field venture and the availability of cane was uncertain. The annual sugarcane yield fluctuates[17] based on rainfall and regional climatic conditions and is highly unpredictable in nature.

[16] Refer Annex 3 for details on historic sugar cane output in the project activity location

[17] Year-wise graphs for production of sugarcane in Andhra Pradesh and India are given in Annex 3.

Impacts	Reduced fuel availability to the project activity resulting in lower load factor or complete shutdown. Higher fuel cost in case of purchase of additional biomass from adjacent areas. The cane output may reduce significantly below normal in periods of drought leading to a corresponding reduction in bagasse availability. This would demand SSAPL to either reduce the power available for export or purchase high cost outside biomass. Both of these options would result in lower returns for SSAPL since the former would reduce the energy sale revenues while the later would increase the generation cost. Thus the performance of the project activity is linked and varies with the performance of the primary product (sugar). Any negative performance of the sugar plant would be amplified by a corresponding loss from the project activity. SSAPL considered it risky to invest in such a project activity when the availability of cane and the successful operation of the sugar plant itself were not established. The rated versus actual cane crushing for the last three years is provided below. It may be observed that cane crushed is significantly lower than the rated capacity. This has resulted in the purchase of additional biomass during the season and also lower load factor of the project activity. 
Effects	Lower revenue realisation resulting in poor or negative profitability, difficulty in servicing loans and cash flow problems.

To summarize, SSAPL had faced prohibitive barriers to implement the project activity in terms of uncertainty in performance/technology, tariff policy and climatic barriers, some of which have been realised. However, SSAPL has implemented the green field power project to export additional electricity to the grid considering that VCS revenues could compensate any financial losses occurring from the realisation of the above risks.

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

- ***Technical barriers:***

Baseline alternative 1 (BA1):

The lower pressure cogeneration plant is well established in the region and would not involve much technical problems and therefore does not involve technological risks. Experienced manpower would also be not a problem since this is common practice in the region.

Baseline alternative 2 (BA2):

The technological barriers are applicable to this alternative and could prohibit the implementation of the project activity not undertaken as a VCS project activity.

- ***Tariff and climatic barriers:***

Baseline alternative 1 (BA1):

Since this alternative doesn't involve significant export of power to grid, the tariff risks would not impact this alternative significantly. Also, since there is no significant power export, the climatic risks would not impact this alternative significantly.

Baseline alternative 2 (BA2):

The tariff and climatic barriers are applicable to this alternative and could prohibit the implementation of the project activity not undertaken as a VCS project activity.

The list of baseline alternative after Step 2 "Barrier analysis" is:

Baseline option 1 (BA1):

- Installation of a bagasse based cogeneration system with an efficiency that is common practice in the sugar mill sector of the region (i.e., with 43 ata operating pressure). The thermal firing capacity will be same as that of the project activity. Since the operating pressure of this system (43 ata) is lower than that of the project plant (67 ata), the electrical efficiency is also lower than the project plant.

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

In the similar project sector, socio-economic environment and geographic conditions, the high pressure cogeneration technology was not a common practice. The project activity was started in March 2000 and was commissioned in January 2003.

According to an MNES report [18], at the time of starting of project activity in March 2000, only 3 sugar plants in the state of Andhra Pradesh had co-generation and were exporting power to the APTRANSCO grid with the maximum capacity being 4.5 MW. In 2000-01, 5 more plants were commissioned all with capacity less than that of the project activity. At the time of implementation, the boiler capacity of 67 ata and generating capacity of 20 MW was a pioneering effort in the state of Andhra Pradesh and was one among the first few in the country. Out of the total potential for bagasse cogeneration in Andhra Pradesh of 200 MW, installed capacity was 35 MW in 2000-01. At the time of start of project activity the technology employed was state-of-the-art since all other similar plants had boiler capacities of around 43 ata. As of 2002-03, out of about 500 [19] sugar mills in the country producing sugar, ethanol and electricity for their own consumption only about 40 [20] mills have gone in for export of power to the grid by expanding their power plants.

[18] *Soft copy of the document being submitted to DOE*

[19] *Ministry of Food, Consumer Affairs & Public Administrati on: Clause 2.1 at* http://fcamin.nic.in/Tuteja%20Committee%20Report.htm

[20] *Ministry of Non-conventional Energy Sources (MNES):* http://mnes.nic.in/bmp17prg.htm

3 Monitoring:

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

- ***Title & Reference of the methodology***

Methodology Details	Description
Methodology Title	Consolidated methodology for electricity generation from biomass residues
Scale	Large Scale – Consolidated
Sectoral Scope:	1 – Energy Industries (renewable -/ non – renewable sources)
Version No	8
References	The methodology refers to the latest approved version of the followings 1. ACM0002 ("Consolidated baseline methodology for grid-connected electricity generation from renewable sources") 2. Combined tool to identify the baseline scenario and demonstrate additionality 3. Tool to calculate baseline, project and/or leakage emissions from electricity consumption 4. Tool to calculate project or leakage CO2 emissions from fossil fuel combustion 5. Tool to determine methane emissions avoided from disposal of waste at a solid waste disposal site.
Weblink	http://cdm.unfccc.int/methodologies/DB/21340DWSMIAU27O7K6VSYQMXMUBK80/view.html

- ***Explanation of the methodology choice***

This section elaborates on the formula used to calculate the project emissions, baseline emissions, leakage and net emission reductions based on ACM0006 version 08 and also indicate the choices made in applying the formula.

As defined in section 2.4 and 2.5 above, the baseline alternative 1 is the most likely baseline scenario which is a combination of options P4, P5, H2 and B4. This corresponds to scenario 04 of ACM0006 version 08 and therefore, for this project activity, the formula applicable to baseline scenario 04 would be used.

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

The detailed information on the monitoring aspects of all the parameter monitored as part of the project activity including purpose of monitoring, type of data & information to be reported, origin of the data, monitoring & calculation approaches, monitoring times & periods and monitoring roles and responsibilities are given in section 3.3 and 3.4.

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

Data / Parameter:	**$BF_{captive\ bagasse,y}$ (Captive bagasse)**
Data unit:	Tonnes of dry matter
Description:	Quantity of bagasse (in-house generated) 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 SSAPL fuel log books.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	57,384
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-VCS 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-VCS 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:	**$BF_{T,k,y}$ (purchased biomass residues)**
Data unit:	Tonnes of dry matter
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 SSAPL fuel log books.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	54,196
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-VCS 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-VCS 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**

Data unit:	% water content
Description:	Moisture content of biomass type k combusted
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% (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-VCS 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:	Weighing scale used would be calibrated annually
Any comment:	

Data / Parameter:	**AVD_y**
Data unit:	Kilometres (Kms)
Description:	Average round trip distance between biomass fuel supply sites and the project site
Source of data to be used:	Records by SSAPL 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	200
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:	N_y
Data unit:	-
Description:	Number of truck trips for the transportation of biomass
Source of data to be used:	On-site measurements SSAPL biomass purchase records. Recorded by the SSAPL weigh bridge operator
Value of data applied for the purpose of calculating expected emission reductions in section B.5	10840
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 SSAPL 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:	$EF_{km,CO2,y}$
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 CO_2 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	0.000653

section B.5	
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 CO2 emission factor for transportation of biomass with trucks

Data / Parameter:	$EF_{CO2,i,y}$
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:	$FF_{project\ plant,i,y}$
Data unit:	Tonnes
Description:	Onsite fossil fuel consumption of type 'i' for co-firing in the project plant
Source of data to be used:	SSAPL boiler fuel log books
Value of data applied for the purpose of	0 (Envisaged only during emergencies. Actual value would be monitored when used)

calculating expected emission reductions in section B.5	
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-VCS 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-VCS 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:	SSAPL 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
Source of data to be used:	SSAPL Energy meter log books
Value of data applied for the purpose of calculating expected emission reductions in section B.5	101529.60
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 SSAPL. 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	Determined by a third party laboratory. Every six months, the lab technician would collect and sends three samples to the third

procedures to be applied:	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	15.49 (for bagasse)
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:	

3.4 Description of the monitoring plan

SSAPL has established a good operational and management structure in running its sugar plant and the cogeneration plant. The best practices of operation and management prevalent in the industry has been adopted by them which will also be extended to the VCS project activity. A special VCS team constituting members from the power plant and sugar factory has been formed. The team includes the power plant, process, maintenance, instrumentation, electrical and other department heads and operators. The responsibility of monitoring and recording all VCS parameters has been assigned to specific members in the team. Monitoring reports will be verified by the respective department heads periodically and sent to the team head for consolidation and storage. Periodic meetings of the VCS team are held to review the performance of the project activity and plan for its sustainable operation. The monitoring information is further detailed in Annexure 2.

4 GHG Emission Reductions:

4.1 Explanation of methodological choice:

4.1.1 Project Emissions:

With reference to ACM0006 version 08, it is required to account:

- *CO2 emissions from the combustion of fossil fuels used by the project activity (during unavailability of bagasse / drought / any other unforeseen circumstances)*
- *CO2 emissions from transportation of biomass from other sites to the project activity*
- *CO2 emissions from electricity consumption*
- *CH4 emissions from biomass combustion (if included in the project boundary)*
- *CH4 emissions from waste water treatment*

Such emissions are calculated by using the below equations:

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

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).

4.1.1.1 Carbon dioxide emissions from transportation of biomass to the project site (PET_y):

ACM0006 version 08 provides two options for the calculation of such emissions. For this project activity, option 1 has been selected.

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

Where:

N_y	Number of truck trips during the year y
AVD_y	is the average return trip distance between the biomass fuel supply sites and the site of the project plant in kilometres (km), and

$EF_{km,CO2}$	is the average CO2 emission factor for the trucks measured in tCO_2/km

4.1.1.2 Carbon dioxide emissions from on-site consumption of fossil fuels ($PEFF_y$):

For scenario 4 of ACM0006 version 08, emissions need to be calculated as per "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion" for the following two combustion processes:

- *Fossil fuel co-fired in the project plant during year y*
- *Fossil fuels combusted at the project site for other purposes (apart from co-firing) that are attributable to the project activity during year y*

Total project emissions from on-site fossil fuel consumption ($PEFF_y$) are calculated as follows:

$$PEFF_y = PE_{FC,projectplant,y} + PE_{FC,projectsite,y}$$

Where:

$PE_{FC,projectplant,y}$	are the CO2 emissions from fossil fuel co-firing in project plant during the year y in (tCO2 / yr);
$PE_{FC,projectsite,y}$	are the CO2 emissions from fossil fuel consumption at project site apart from co-firing during the year y in (tCO2 / yr);

$PE_{FC,projectplant,y}$ and $PE_{FC,projectsite,y}$ are calculated as per the "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion" as follows:

$$PE_{FC,j,y} = \sum_i FC_{i,j,y} \times COEF_{i,y}$$

Where:

PEFCj,y	are the CO2 emissions from fossil fuel combustion in process j during the year y in (tCO_2/yr);
$FC_{i,j,y}$	Quantity of fossil fuel type i combusted in process j during year y (in tonnes)
$COEF_{i,y}$	is the CO2 emission coefficient of fuel type i in year y (tCO_2/ tonnes)
i	are the fuel types combusted in processes j

The above formula is applied for processes "fossil fuel co-firing in project plant" and "fossil fuel combustion in project site apart from co-firing".

Project emissions from fossil fuel co-firing in the project plant:

$$PE_{FC,projectplant,y} = \sum_i FC_{i,projectplant,y} \times COEF_{i,y}$$

Where:

$PE_{FC,projectplant,y}$	are the CO2 emissions from fossil fuel co-firing in project plant during the year y in (tCO_2/yr);
$FC_{i,projectplant,y}$	Quantity of fossil fuel type i co-fired in project plant during year y (in tonnes)
$COEF_{i,y}$	is the CO_2 emission coefficient of fuel type i in year y (tCO_2/tonnes)
i	are the fuel types co-fired in project plant

Project emissions from fossil fuel consumption at project site apart from co-firing:

$$PE_{FC,projectsite,y} = \sum_i FC_{i,projectsite,y} \times COEF_{i,y}$$

Where,

$PE_{FC,projectsite,y}$	are the CO2 emissions from fossil fuel consumption at project site apart from co-firing during the year y in (tCO_2/yr);
$FC_{i,projectsite,y}$	Quantity of fossil fuel type i consumed at project site apart from co-firing during year y (in tonnes)
$COEF_{i,y}$	is the CO_2 emission coefficient of fuel type i in year y (tCO_2/ tonnes)
i	are the fuel types consumed at project site apart from co-firing

Calculation of CO_2 emission coefficient of fuel type i in year y ($COEF_{i,y}$):

The "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion" provides two methods "Option A or Option B" for the calculation of COEFi,y. For this project activity, option B is selected since the necessary data for Option A (w – mass fraction of carbon in fuel) is not available.

As per option B of the tool, COEFi,y is calculated as below:

$$COEF_{i,y} = NCV_{i,y} \text{ X } EF_{CO2i,y}$$

Where,

$NCV_{i,y}$	is the net calorific value of fossil fuel type i co-fired or consumed on-site in the project activity in year y (in GJ/tonne)

$EF_{CO2,i,y}$ is the weighted average CO2 emission factor of fuel type i co-fired or consumed on-site in the project activity in year y(in tCO_2/GJ)

4.1.1.3 Carbon dioxide emissions from electricity consumption ($PE_{EC,y}$):

Electricity may be imported by the project activity from the grid or from a standby DG set for start-up/maintenance purposes. However, these would have happened in the baseline case also and therefore, there is no incremental electricity consumption as a result of the project activity. The auxiliary electricity consumption of the power plant is accounted by considering only the “net generation” in the baseline emission calculations.

4.1.1.4 Methane emission from combustion of biomass residues

This is not applicable to this project activity as it is excluded from the project boundary both for the calculation of baseline emissions and project emissions.

4.1.1.5 Methane emissions from waste water generated from the treatment of biomass residues

For this project activity, there is no treatment of biomass residues or waste water from such treatment and therefore this source need not be accounted

4.1.2 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 (EGy) with the CO2 baseline emission factor for the electricity displaced due to the project (EFelectricity,y), as follows:

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

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)

4.1.2.1 Determination of emission factor for electricity displaced ($EF_{electricity,y}$):

As per ACM0006 version 08, for project activities under scenario 4, emission factor for the displacement of electricity should correspond to the grid emission factor which shall be determined as follows:

If the power generation capacity of the biomass power plant is more than 15 MW, EFelectricity,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). The emission factor is determined in the following three steps:

As prescribed by ACM0002 version 09, combined margin emission factor of the grid is based on the "Tool to calculate the emission factor for an electricity system, calculated as follows:

Baseline Emission Factor/Emission Coefficient (EFy, tCO2/MWh)

CEA (www.cea.nic.in) is the statutory organization and its main objective is to advise the Government of India (Host Party) on any of the matters relating to the national electricity policy, formulate short-term and perspective plans for development of the electricity system and coordinate the activities of the planning agencies for the optimal utilization of resources to sub serve the interests of the national economy and to provide reliable and affordable electricity to all consumers. CEA has made an elaborate study and has determined electricity baseline emission factor for all regional grids in India in a conservative and transparent manner for both the options of weighted average emissions and on combined margin approach.

This made available at their website for usage by all the CDM project developers and VCS project developers and it is publicly available at http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm. The version no. 4 dated 1st September 2008 has been used in this project activity. CEA has adapted the latest version of the tool (Tool to calculate the Emission Factor for an electricity system), Version 01.1 for the calculation of baseline emission factor [21]. The procedures followed, the assumptions made and the formulae applied by the CEA for the calculation of the OM and the BM are detailed below.

Calculation of Baseline Emission Factor/Emission Coefficient (tCO_2/MWh)

STEP 1. Identify the relevant electric power system

For the purpose of determining the electricity emission factors, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity (e.g. the renewable power plant location or

[21] http://cea.nic.in/planning/c%20and%20e/user_guide_ver3.pdf

the consumers where electricity is being saved) and that can be dispatched without significant transmission constraints. Similarly, a connected electricity system, e.g. national or international, is defined as an electricity system that is connected by transmission lines to the project electricity system. Power plants within the connected electricity system can be dispatched without significant transmission constraints but transmission to the project electricity system has significant transmission constraint. The tool recommends using the following criteria to determine the existence of significant transmission constraints

In case of electricity systems with spot markets for electricity: there are differences in electricity prices (without transmission and distribution costs) of more than 5 percent between the systems during 60 percent or more of the hours of the year.

The transmission line is operated at 90% or more of its rated capacity during 90% percent or more of the hours of the year.

In the Indian context, as no well established spot markets exist, the first criterion is not applicable. Similarly, a transmission line fulfilling the second criteria is an exception in Indian Context. As the application of above criteria does not result in a clear grid boundary, tool recommends to use a regional grid definition in the case of large countries with layered dispatch systems (e.g. provincial / regional / national). Further, the tool also states that a provincial grid definition may indeed in many cases be too narrow given significant electricity trade among provinces that might be affected, directly or indirectly, by a VCS project activity. In other countries, the national (or other largest) grid definition should be used by default.

The proposed bundled project activity is located in Nelavoy Village in the state of Andhra Pradesh and will be feeding the electricity generated to the southern regional grid serving the six southern states (Tamilnadu, Kerala, Karnataka, Andhra Pradesh, Pondicherry & Lakshadweep. All the electricity generating units connected to this southern grid would be part of the boundary for estimation of baseline emissions. The other regional grids connected to southern grid are not included in the boundary for estimation of baseline emissions since the net exchange of energy within the grids is very small and negligible.

The proposed project activity would displace electricity generation in the southern grid and the displaced electricity generation is the element that is likely to affect both the operating margin (in short run) and the build margin (in long run). Hence, the baseline establishment should reflect a combination of both these effects and therefore, an ideal approach is to combine both operating margin and build margin according to the procedures laid out in the above said tool. Therefore “Combined Margin Emission Factor” has been adopted for calculating emission reductions for this project activity and this has been taken from Central Electricity Authority (CEA):CO2 Emission Database.

STEP 2. Select an operating margin (OM) method

The project proponent wishes to use the Simple Operating Margin (OM) method for the estimation of the Operating Margin Emission Factor. The use of the Simple OM method is justified as the share of the low cost/ must run resources constitute less than 50% of the total grid generation. The data pertaining to the total grid generation and the low/cost must run resources have been included in Annex 1. The Ex ante option "A 3-year generation-weighted average, based on the most recent data available at the time of submission of VCS PD to the DOE for validation, without requirement to monitor and recalculate the emissions factor during the chosen 10 years crediting period" has been chosen.

STEP 3. Calculate the operating margin emission factor ($EF_{grid,OMsimple,y}$) according to the selected method.

For this approach (simple OM), the operating margin is calculated as the generation-weighted average CO_2 emissions per unit net electricity generation (tCO_2/MWh) of the power plants / units delivering electricity to the grid, not including low-cost/must-run power plants / units, and including electricity imports to the grid. The assumptions used by CEA while calculating the CO_2 emissions are detailed in Appendix B of the "CO2 baseline database for the Indian Power Sector – User Guide[22]"

Calculation Approach

The operating margin describes the average CO2 intensity of the existing stations in the southern grid which are most likely to reduce their output if a VCS project supplies electricity to the southern grid (or reduces consumption of grid electricity). Simple operating margin emission factor has been used for emission factor calculation. The simple operating margin is the weighted average emissions rate of all generation sources in the region except so-called low-cost or must-run sources3. In India, hydro and nuclear stations qualify as low-cost / must-run sources and are excluded. The operating margin, therefore, is calculated by dividing the region's total CO2 emissions by the net generation of all thermal stations. In other words, it represents the weighted average emissions rate of all thermal stations in the southern grid calculated as given below[23]:

$$EF_{grid,OMsimple,y} = \frac{\sum_{i,m} FC_{i,m,y} \ X \ NCV_{i,y} \ X \ EF_{CO2i,y}}{EG_{m,y}}$$

Where;

$EF_{grid,OMsimple,y}$ = Simple operating margin CO2 emission factor in year y (tCO_2/MWh)

[22] http://cea.nic.in/planning/c%20and%20e/user_guide_ver4.pdf

[23] http://cdm.unfccc.int/Reference/tools/ls/meth_tool07_v01_1.pdf

$FC_{i,m,y}$	Amount of fossil fuel type i consumed by power unit m in year y (Mass or volume unit)
$NCV_{i,y}$	Net calorific value of fossil fuel type i in year y (GJ / mass or volume unit)
$EF_{CO2,i,y}$	CO2 emission factor of fossil fuel type i in year y (tCO2/GJ)
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
m	All power units serving the grid in year y except low-cost / must-run power units
i	All fossil fuel types combusted in power unit m in year y
Y	Either the three most recent years for which data is available at the time of submission of the VCS-PD to the DOE for validation (ex ante option) or the applicable year during monitoring (ex post option)

The project proponent uses the baseline emission factor calculated ex-ante, and has fixed the same for the entire crediting period.

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

The build margin reflects the average CO2 intensity of newly built power stations that will be (partially) replaced by a VCS project. In accordance with the Grid Tool, the build margin is calculated in CEA: CO2 Baseline database as the average emissions intensity of the 20% most recent capacity additions in the grid based on net generation.

STEP 5. Calculate the build margin emission factor ($EF_{grid,BM,y}$)

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units m during the most recent year y for which power generation data is available, calculated as follows

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

Where;

$EF_{grid,BM,y}$	= Build margin CO2 emission factor in year y (tCO_2/MWh)
$EG_{m,y}$	= Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
$EF_{EL,m,y}$	= CO_2 emission factor of power unit m in year y (tCO_2/MWh)
m	= Power units included in the build margin

y = Most recent historical year for which power generation data is available

The build margin emission factor for the most recent year (2007-08) is considered in this project activity.

Source: Central Electricity Authority: CO2 Baseline Database, Version 04 dtd 01 September 2008

STEP 6. Calculate the combined margin (CM) emissions factor

As described in step 6 in the referred tool, the baseline emission factor i.e. the combined margin emission factor in this case is calculated as follows:

$$EF_y = \left(EF_{grid,OM,y}\ X\ W_{OM}\right) + \left(EF_{grid,BM,y}\ X\ W_{BM}\right)$$ Where,

$EF_{grid,OM,y}$ = Operating margin CO_2 emission factor in year y (tCO_2/MWh)

EFgrid,BM,y = Build margin CO_2 emission factor in year (tCO2/MWh)

W_{OM} = Weighting of operating margin emissions factor (%)

W_{BM} = Weighting of build margin emissions factor (%)

EFy = 0.85573754 tCO2/MWh

After allowing the operating margin and build margin emission factor taken from CEA: CO_2 baseline database for the southern grid for the most recent three years and the most recent year respectively, the resulting combined margin emission factor is 0.85573754 tCO_2 /MWh. The detailed data on CEA: CO2 baseline database is in given in Annexure 1

4.1.2.2 Determination of EGy:

For scenario 4, ACM0006 prescribes the following equation to determine EGy:

$$EG_y = EG_{\text{project plant, y}} - \varepsilon_{el,\text{ other plant(s)}} \cdot \frac{1}{3.6} \cdot \sum_k BF_{k,y} \cdot NCV_k$$

Where,

EGy	Net quantity of increased electricity generation as a result of the project activity (incremental to baseline generation) during the year y (MWh)
$EG_{project\ plant,y}$	Net quantity of electricity generated in the project plant during the year y (MWh)
$BF_{k,y}$	Quantity of biomass residue type k combusted in the project plant during the year y (litres)
NCV_k	Net calorific value of the biomass residue type k (GJ/litre)
$\varepsilon_{el,other\ plant(s)}$	Corresponds to the average net efficiency of electricity generation in the other power plant(s) that would use the biomass residues

fired in the project plant in the absence of the project activity ($MWh_{el}/MWh_{biomass}$). Where scenario 4 applies, this corresponds to average net efficiency of electricity generation in the "reference plant" that would be installed in the absence of the project activity.

4.1.3 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 4, 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(s) 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. Here, the additional heat generation is achieved through firing additional biomass residues in the project plant[24]. As described in ACM0006 (page 43-44), for such cases, the additional heat generation can be assumed not to involve additional emissions. Therefore, it is assumed that $ER_{heat,y} = 0$ for this project activity.

4.1.4 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 4 of ACM0006 and therefore does not require addressing leakage. There is no leakage of emission reductions.

4.1.5 Emission Reductions:

As per ACM0006 version 08, emission reductions are calculated as below:

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

[24] There is neither fossil fuel based plants nor biomass based (h eat only) boilers at the site. Therefore, it may be concluded that the additional heat is generated by firing additional biomass residues.

Where,

ERy	Are the net emissions reductions of the project activity during the year y in tons of CO_2
ERheat,y	Are the emission reductions due to displacement of heat during the year y in tons of CO_2
$ER_{electricity,y}$	Are the emission reductions due to displacement of electricity during the year y in tons of CO_2
$BE_{biomass,y}$	Baseline emissions due to natural decay or burning of anthropogenic sources of biomass residues during the year y (tCO_2e/yr)
PE_y	Are the project emissions during the year y in tons of CO_2
L_y	Are the leakage of emission reductions during the year y in tons of CO_2

For this project activity, ERheat = 0 (Refer section B.6.1.3 above). Baseline emissions due to natural decay or uncontrolled burning are excluded from the project boundary ($BE_{biomass,y}$ = 0). Leakage L_y=0 (Refer section B.6.1.4 above). Therefore the emission reduction equation for this project activity reduces to:

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

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

Emissions reductions from electricity displacement:

S.N	Notation	Parameter	Unit	Value	Comments
1	$EG_{project\ plant,y}$	Net quantity of electricity generated in project plant per annum	MWh/yr	101529.60	Refer Annex 4
2	$BF_{k,y(wet)}$	Quantity of biomass residue (wet basis) combusted in project plant per annum	Tonnes/yr	224515.20	Refer Annex 4
3	$BF_{k,y}$	Average moisture content of biomass residue type k	%	50	For bagasse
4	$BF_{k,y(dry)}$	Quantity of biomass residue (dry basis) combusted in project plant per annum	Tonnes/yr	112257.60	Adjusting for moisture content
5	$NCV_{k,y}$	Net calorific value of the dry biomass residue	GJ/tonnes	15.07	NCV of bagasse on a dry basis
6	$\bullet_{el,\ other\ plants}$	Average efficiency of electricity generation of power plants that would use the biomass in the absence of the project activity	$MWh_e/MWh_{biomass}$	0.1279	
7	• ($BF_{k,y}$ * $NCV_{k,y}$) (4*5)	Total heat equivalent of all biomass combusted in the project plant during year y	$MWh_{biomass}$	470022.57	Methodology formula. Refer section B.6.1 above.
8	EG_y [1 – (6*7/3.6)]	Net quantity of increased electricity generation as a result of the project activity	MWh/yr	41418.78	Methodology formula. Refer section B.6.1 above.
9	$EF_{electricity,y}$	CO2 emissions factor for the electricity displaced due to the project activity	tCO_2/MWh	0.855737	Refer Annexure 1

		during the crediting period			
10	$ER_{electricity,y}$ (8*9)	Emission reductions due to displacement of electricity per annum	tCO_2/yr	35443	Methodology formula. Refer section B.6.1 above.

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

Project emissions:

Emissions due to combustion of fossil fuels in the project activity:					
S.No	**Notation**	**Parameter**	**Unit**	**Value**	**Comments**
1	$FC_{i,project\ plant,y}$	Quantity of fossil fuel type i co-fired in project plant	T/yr	0	Will be measured if used. Envisaged only during emergencies.
2	$FC_{i,project\ site,y}$	Quantity of fossil fuel type i consumed on-site apart from co-firing in project activity	T/yr	0	Not expected
3	$NCV_{i,y}$	Net Calorific Value of fuel type i	GJ/T fossil fuel	0	Will be measured if used. Envisaged only during emergencies.
4	$EF_{CO2,i,y}$	CO2 emission factor for fuel type i	tCO2/GJ	-	
5	$COEF_{CO2,i,y}$ (3*4)	CO2 emission coefficient for fuel type i	tCO2/T	-	
6	$PE_{FC,projectplant,y}$(1*5)	CO2 emissions from fossil fuel co-firing	tCO2/yr	0	
7	$PE_{FC,projectsite,y}$ (2*5)	CO2 emissions from on-site fossil fuel consumption other than co-firing	tCO2/yr	0	Methodology formula
8	$PEFF_y$ (6+7)	Total project emissions from fossil fuel combustion	tCO2/yr	0	

Emissions due to combustion of fossil fuels for transportation of biomass:					
S.No	**Notation**	**Parameter**	**Unit**	**Value**	**Comments**
1	N_y	Number of truck trips during the year y	-	10906	Estimated based on purchase of biomass residues (bagasse) for 170 days of off-season peration (108392 Tonnes) and an average truck load of 10 tonnes. (72826/10 = 7283)Refer Annex 4 for outside biomass residue quantity details.
2	AVD_y	Average return trip distance between the biomass fuel supply sites and the project plant	kms	200	Conservative assumption. ACM0006 prescribes a minimum value of 20 kms.
3		Average truck mileage	kms/litre diesel	4	Data from truck operator
4		Fuel consumption per kilometre	litres/kms	0.250	
5		Fuel consumption per kilometre	t/kms	0.2125 X 10-3	Based on fuel density of 0.85 as per Bureau of Energy Efficiency
6		Net calorific value of diesel	TJ/tonne of diesel	0.043	IPCC 2006 default value for diesel
7		CO2 emission factor	tCO2/TJ	71.428	IPCC 2006 default value for diesel
8	$EF_{km,co2,y}$ (5*6*7)	CO2 emission factor	tCO2/km	0.6526 X 10-3	
9	PET_y (1*2*8)	CO2 emissions from transportation	tCO2/yr	1424	

Total project emissions:

S.No	Notation	Parameter	Unit	Value
1	PET_y	CO2 emissions from biomass transportation	tCO2/yr	1424
2	$PEFF_y$	CO2 emissions from fossil fuel consumption	tCO2/yr	0
3	PE_y (1+2)	Total project emissions	tCO2/yr	1424

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

Net Emission reductions

S.No	Notation	Parameter	Unit	Value
1	$ER_{electricity,y}$	Emission reductions from electricity displacement	tCO2/yr	35,443
2	PE_y	Project emissions	tCO2/yr	1,424
3	ER_y (1-2)	Emission reductions	tCO2/yr	34,019

Emission Reductions from the high efficiency cogeneration project activity at SSAPL, AP					
Period	Incremental Electricity Generation (EGy)	Grid Emission Factor (EF)	Emission reductions from electricity displacement (ERel)	Project Emissions (PE)	Emission Reductions (ERs)
	MWh	tCO_2/MWh	tCO_2	tCO_2	tCO_2
2008-09	41,418.78	0.85	35,443	1,424	34,019
2009-10	41,418.78	0.85	35,443	1,424	34,019
2010-11	41,418.78	0.85	35,443	1,424	34,019
2011-12	41,418.78	0.85	35,443	1,424	34,019
2012-13	41,418.78	0.85	35,443	1,424	34,019
2013-14	41,418.78	0.85	35,443	1,424	34,019
2014-15	41,418.78	0.85	35,443	1,424	34,019
2015-16	41,418.78	0.85	35,443	1,424	34,019
2016-17	41,418.78	0.85	35,443	1,424	34,019
2017-18	41,418.78	0.85	35,443	1,424	34,019
Total	414,187.81		354,430	14,240.00	3,40,190
Average	41,418.78				34,019

5 Environmental Impact:

Summary of Environment Audit Report

The environmental impacts are categorized as primary or secondary impacts. Primary impacts are those that can be attributed directly to the project itself and secondary impacts are those, which are induced indirectly because of the development activity or may be triggered by the primary impact. The secondary impacts usually include investment and changes in socio-economic activity by the project activity.

The impact of the project on the environment occurs during two stages:

1. Construction phase
2. Operational phase

The project activity has been set up adjacent to the sugar manufacturing unit at Nelavoy village. The infrastructure for the project included land, fuel (bagasse) storage and transfer facilities, switchyard, and other support systems.

Environmental impacts during construction phase:

The environmental impacts due to the construction of the project activity are as given below:

Air quality impact:

- Particulate emissions from site clearing
- Particulate emissions from offsite quarrying operations
- Vehicular emissions (NO_x, SO_2, SPM) from transportation of raw materials such as cement, sand, gravel etc.
- Particulate emissions from various construction activities including pre-casting, fabrication, welding etc.

Noise level increase:

- From earth moving equipments used for site clearing
- From offsite quarrying operations
- From transporting raw materials including cement, sand, gravel etc
- From onsite construction activities

Land and soil impacts:

- From change/ replacement of previous land-use by site clearing
- From soil erosion due to vegetation removal
- 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 occurred during the construction phase of the cogeneration plant. The environmental impacts from the above activities were minimized by implementing the mitigation measures during the construction.

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

Impacts during operational phase

The operational phase of the project activity involves power generation from bagasse used as fuel. The cogeneration plant feeds surplus power to the grid and indirectly prevents the pollutants that would otherwise have been released into the atmosphere from the thermal power plants (coal, gas and diesel based) of the State grid. Also, bagasse being a biomass (a renewable fuel) does not add any net CO2 to the atmosphere as the carbon gets recycled during cane growth.

The optimal utilization of bagasse by the cogeneration plant avoids and prevents the pollution from other alternative methods of bagasse disposal practiced in sugar plants i.e. inefficient burning of bagasse in boilers or allowing 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 project activity are as given here:

Air quality impacts:

The project activity discharges the following pollutants into the air:

- Suspended Particulate Matter (SPM) from fly ash in the flue gas
- Oxides of Nitrogen (NO_x) in the flue gas
- Carbon dioxide (CO_2)

The combustion gases are discharged through a stack of 76 m height, which meets the requirement for minimum stack height prescribed by the Central Pollution Control Board (CPCB).

As the pollution control regulations limit the particulate matter emissions from bagasse fired steam generators to 115mg/Nm3, electrostatic precipitators (ESP’s) of 97% efficiency are provided in the project activity reducing SPM levels to 106mg/Nm3. The NOx emissions are restricted to 31mg/Nm3 by proper controls at the combustion stage.

The 24 hr incremental ground level concentrations (GLCs) of NOx and SPM25 respectively due to the project activity are 8.8 and 86.2 mg/Nm3. The predicted GLCs are within the National Ambient Air Quality Standards (NAAQS) for the industrial area. The SO2 level is not anticipated to increase from the power plant operations.

To reduce to ground level air contaminants, a 76 m stack was suggested for bagasse-fired boiler, which has helped in faster dispersion of air pollutants into the atmosphere thus reducing the impact on the project surroundings.

During shortage of bagasse in-house, the bagasse is transported (a distance of 100 km) from nearby sugar factories to the project site. However, the air emissions would be very negligible.

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

Noise level increase:

Noise levels shall be monitored for assessing any possible adverse impacts on the workers of the factory and people living in the nearby habitations. Noise levels are monitored with the use of noise level meters at different times covering all three shifts. The noise levels at different sections are shown in the table below. The levels at all points are less than the standards prescribed by the Ministry of Environment and Forests, vide notification, dated 14-02-2000 i.e. 75 dBA during daytime and 70 dBA during night time.

NOISE LEVELS (*Date of measurement: 04-03-2004)*

<table>
<tr><th>Location</th><th>Daytime Noise level (in dBA)</th><th>Night time noise level (in dBA)</th><th>Permitted ambient noise levels as per MOEF notification dated 14-02-2000 (dBA)</th></tr>
<tr><td>Near D.M. Plant</td><td>59</td><td>51</td><td rowspan="3">75 (Daytime)
70 (Night time)</td></tr>
<tr><td>Near Power Block</td><td>63</td><td>52</td></tr>
<tr><td>Near Weigh Bridge</td><td>56</td><td>49</td></tr>
</table>

[25] Source: Comprehensive Environment Audit Report for the 20 MW cogeneration power plant at SSAPL by Pioneer Enviro Labs and Consultants Private Limited

Water quality impacts:

The effluents generated from the project activity are being treated in the effluent treatment plant before final discharge. This is to ensure that there is no environmental deterioration by following the mitigation measures as given below:

- The demineralization plant waste is neutralized in the neutralization plant to bring the pH level in the range of 5.5 – 9 as per regulatory standards.
- Oil contamination is removed by oil & grease traps.
- The plant sanitary waste is treated in aeration tanks to bring down the biochemical oxygen demand (BOD) level to acceptable limits.
- Treated wastewater is used for irrigation.
- Wastewater for irrigation meets the respective standards.

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

Ecological impacts:

The ecological impacts are primarily from emission of air pollutants and as the peak concentrations of pollutants are expected to be within NAAQS limits, there is no significant impact on the ecological system.

No ecological impacts are envisaged from wastewater discharge as they are treated appropriately before final disposal.

Land use impacts:

The project activity has not resulted in significant impacts on the land use

Socio-economic impacts

The project activity has contributed to socio-economic growth in the following ways;

- Generation of employment to 50 technical experts in various fields like mechanical, electrical, electronics, instrumentation, chemical engineering etc.
- Project is supplying power to SSAPL and ensuring its smooth operation.
- 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.
- Improvement of financial position of the sugar plant.
- Reduction in fuel transportation costs.

- Reduction in transmission losses.
- Self reliance of power in rural areas.

Environmental Management Plan (EMP)

The EMP has been prepared to basically manage the various impacts arising from construction and operational phases of the project activity.

Construction phase

Air environment

The following measures were undertaken for mitigation of air pollution 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

Operational phase

Air environment

- Electrostatic precipitators (ESP) with an efficiency of 97% have been installed to control particulate emissions so that it does not exceed 115mg/Nm3.
- For good dispersion of pollutants a stack of 76 m height has been constructed as per applicable standards.
- NOx levels will be controlled at combustion stage to 120mg/Nm3.
- 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 for NOx and particulate matter is carried out.
- Ambient air quality monitoring is carried out for NOx, SO2 and SPM periodically.

Noise environment

- Periodic noise control checks on vehicles
- Provision of ear plugs, work rotation, adequate training
- Proper encasing of noise generation sources
- Regular noise level monitoring at the plant and surrounding area

Water environment

- Wastewater is treated to meet the Minimum National Standards (MINAS) and general standards for effluents
- Periodic monitoring of water quality parameters

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 Andhra Pradesh State Pollution Control Board (APPCB) 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 is being undertaken in order to meet the requirements of the Andhra Pradesh State 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 NOx.

6 Stakeholders comments:

The major stakeholders to the project activity are:

- Elected body of representatives administering the local area (Village Panchayat)
- Local residents
- Non Governmental Organizations (NGO's)
- Transmission Corporation of Andhra Pradesh (APTRANSCO)[26]

SSAPL sent formal invitations to the identified stakeholders mentioning the date, time and venue of the stakeholder consultation meeting. During the stakeholder consultation meeting conducted on 07.02.2004, SSAPL appraised the stakeholders about the equipments and technology used in the project activity, fuel used and prospective benefits of GHG reduction and contribution to sustainable development. The environmental aspects of the project were discussed and SSAPL has gathered written responses from the stakeholders, which have been compiled and documented.

Summary of comments received

The stakeholders view the project activity as contributing to socio-economic development without exploiting the local and global environment and natural resources. All the stakeholders who attended the consultation meeting have expressed their consent and appreciation to SSAPL for implementing the project activity

How due account was taken of any comments received

There were no negative comments received and therefore no corrective action was to be made. SSAPL will take all necessary action to operate the project activity in a manner sustainable to the local and global environment and considering the socio-economic conditions.

[26] APTRANSCO has now been restructured in to five different distribution companies. The project activity is connected in the APSPDCL grid.

7 Schedule:

Chronological plan for the date of initiating project activities, date of terminating the project, frequency of monitoring and repo rting and the project period, including relevant project activities in each step of the GHG project cycle.

Frequency of monitoring and reporting:
The details of frequency of monitoring and reporting in included in Section 3.4 in detail.

Project period:
Crediting period – 10 years
Crediting period start – 01 January 2008
Lifetime of the project activity – 20 years

GHG project cycle:
The following are important project activities in the GHG cycle for this project activity:

Date	Activity Description
19/01/2000	Purchase Order date
13/01/2003	Commissioning date
01/01/2008	Start date of crediting period
12/01/2005	Appointment of the consultant
17/09/2008	Appointment of the VCS validator
09/06/2009	Submission of VCS PD to the validator
14/09/2009	Date of validation
20/10/2009	Expected date of validation completion

8 Ownership:

8.1 Proof of Title:

The project activity’s proof of title is substantiated by the following documents, which shall be provided by the project proponent:

- Ownership of land that is proven by land purchase deeds
- Purchase orders issued for acquiring the equipment
- Power purchase agreements signed by the proponent with APSPDCL.

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

Not Applicable

Annexure 1

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 (ACM0002) and is based on "Tool to the calculate emission factor for an electricity system". For further details on the calculation methods and data used, please refer the following weblink:
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 (0.85573754 tCO_2/MWh) has been considered for this project activity

Weighted Average Emission Rate(tCO_2/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 (tCO_2/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 (tCO_2/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 (tCO_2/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

Simple Operating Margin (tCO_2/MWh) (incl. Imports)			
	2005-06	2006-07	2007-08
NEWNE	1.02	1.01	1.00
South	1.01	1.00	0.99
India	1.02	1.01	1.00

Annexure 2

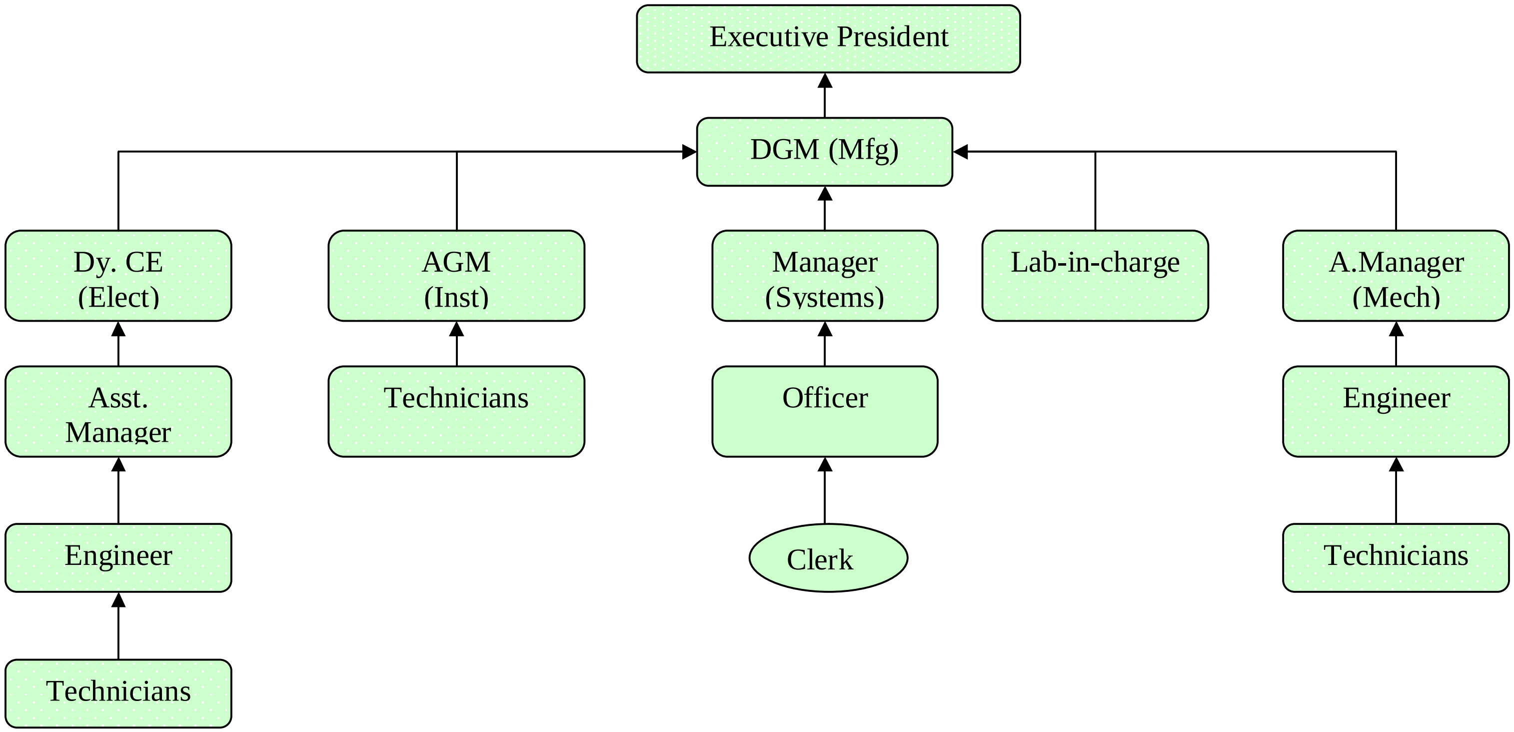
MONITORING INFORMATION

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

VCS TEAM:

The VCS 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 VCS procedures. The organization structure of the VCS team is given as follows.

Organization structure showing the VCS 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 VCS 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 VCS parameters done in line with the VCS PD and VCS Manual
- Is the documentation of monitored VCS parameters done properly
- Are equipments calibrated and maintained as scheduled
- Is the quantity of VCUs generated inline with that projected in the VCS PD? 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 VCS 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 VCS 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 VCS Team meeting (that normally would happen a few days after monthly VCS 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 consultant to all the monitoring personnel identified. Detailed monitoring procedures for each of the VCS 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 VCS Team:

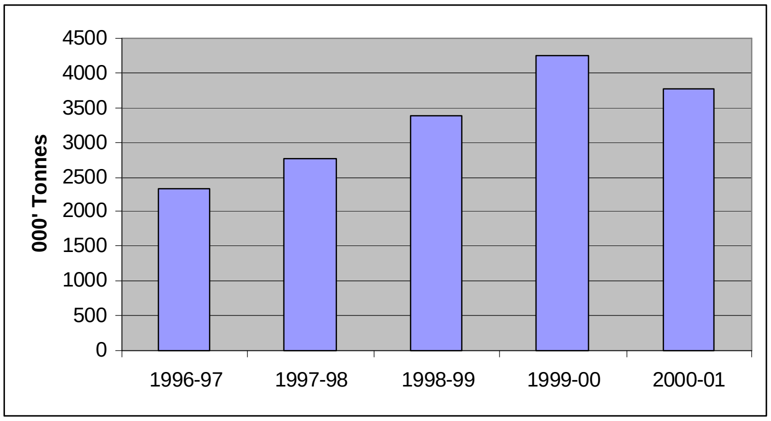
- Monitor parameters for calculating emission reductions generated by the project activity
- Maintain records of relevant data for verification of CERs.
- Ensure accuracy of data by proper maintenance and calibration of monitoring equipment.
- Operate the power plant in compliance with the VCS PD
- Take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

VCS Team meeting:

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

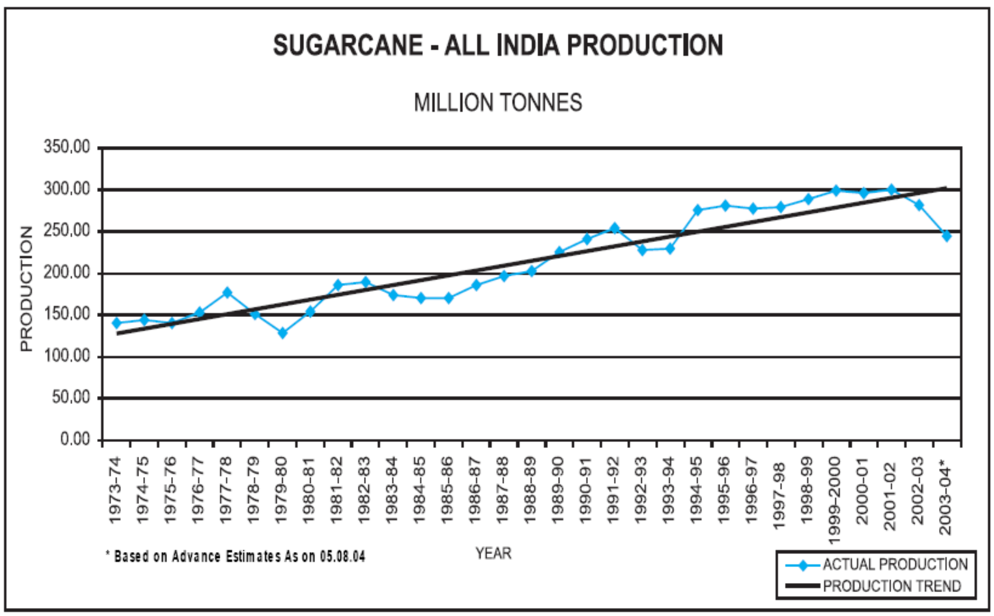
Annexure 3

Chart 1: Year-wise sugar cane output in Chittoor district, Andhra Pradesh



Note: Copy of the document being submitted to DOE

Chart 2: All India – Sugarcane production



Source: a. *http://agricoop.nic.in/Statatglance2004/graphs.pdf*

***b.**Copy of the document being submitted to DOE*

Annexure 4

Summary of Power and Mass Balance of the project activity[27]					
Parameter	**Unit**	**Season**	**Off-season**	**Total**	**Reference**
Installed Capacity	MW	20.0	20.0	-	P.O for TG supply
Gross power generation	MW	14.89	19.24	-	As per detailed project report
Auxiliary Power Consumption	MW	1.7	2.1	-	As per detailed project report
Net Power generation	MW	13.19	17.14	-	As per detailed project report
Captive power Requirement	MW	3.2	0.2	-	As per detailed project report
Power Export to Grid	MW	9.99	16.94	-	As per detailed project report
Fuel type		Bagasse	Purchased bagasse	-	As per detailed project report
Captive bagasse available (wet)	TPH	33.21	-	-	As per detailed project report
Bagasse/Biomass consumed for cogen	TPH	33.21	33.21	-	As per detailed project report
Surplus Bagasse	T	0.00	0.00	-	As per detailed project report
Net Calorific Value	kCal/Kg	3600	3600	-	As per detailed project report
No. of operating days		180.00	170	350	As per detailed project report
Load factor		80.00%	80.00%	-	As per detailed project report
Net Energy generation	MWh	45584.64	55944.96	101530	Calculated value
Total Bagasse/Biomass consumed (wet basis)	T/yr	114768	108392	223160	Calculated value

27 Source: a. Detailed Project Report (DPR)

b. Power Purchase Agreement execut ed between APTRANSCO & SSAPL dated 10.02.2007

Annexure 5 - Abbreviations

SSAPL	Sagar Sugars and Allied Products 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
CO2	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
FYP	Five Year Plan
GHG	Greenhouse Gas
GOI	Government of India
GWh	Gega Watt hour
HP	High Pressure
HV	High Voltage
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
APTRANSCO	Andhra Pradesh Transmission Corporation
APPCB	Andhra Pradesh Pollution Control Board
APERC	Andhra Pradesh Electricity Regulatory Commission
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
p.a	Per annum
PLF	Plant Load Factor

PPA	Power Purchase Agreement
PIN	Project Idea Note
REP	Renewable Energy Projects
SEB	State Electricity Board
SO2	Sulphur Di-oxide
SPM	Solid Particulate Matter
STG	Steam Turbine Generator
TCD	Tones of Crushing per Day
TDS	Total Dissolved Solids
TJ	Trillion Joules
TPH	Tones Per Hour
TERI	Tata Energy Research Institute
UNFCCC	United Nations Framework Convention on Climate Change