CDM
Monitoring Report

Of

"Methane Recovery and Power Generation in a Distillery plant"

By GMR Industries Ltd. (GIDL)

UNFCCC0505

Version 1.1

Monitoring Period:

From: 01/10/2006

To: 31/03/2007

GMR Industries Limited (sugar division)

Sankili, Regidi, Amadalavalasa Mandal,

Srikakulam District – 532440

Andhra Pradesh, India

Date: 30/05/07

Mr.K. Sreeramamurthy, GMR Industires

Table of Contents:

1. Introduction

The purpose of monitoring report is to calculate and clearly demonstrate the GHG emission reduction quantity achieved by this project for periodic verification.

The monitoring report shall cover the activity from **01/10/2006 to 31/03/2007** as first monitoring period.

Starting date of project activity: 01/12/2003
Project Commissioning date: 01/06/2005

Starting date of crediting period (first 7 year crediting period): 01/10/2006

2. Reference

Title: Methane Recovery and Power Generation in a distillery plant.

Version: Ver 01

Date of completion of the Monitoring Report: 30/05/2007

Approved Baseline Methodology:
The project has two components and they confirm to following small scale approved baseline methodologies.

a. Type IIIH: Methane recovery in wastewater treatment.
b. Type ID: Grid connected renewable electricity generation.

Approved Monitoring Methodology:
The project has two components and they confirm to following small scale approved monitoring methodologies.

a. Type IIIH: Comprises Methane recovery from spent wash treatment facilities.
b. Type ID: Comprises renewable energy generation units that displaces electricity based on fossil fuel fired generating stations.

Project Design Document:
Methane recovery and power generation in a distillery plant" by GMR Industries Ltd. (GIDL); UNFCCC reference number - 0505
Version: 1.3
Date: 04/09/2006

3. Definition

4. Description of Project Activity

a. General Description:

This project activity is based at the distillery unit of integrated sugar complex of GMR Industries Ltd. (GIDL - Sugar Division) at Sankili village, Srikakulam District in the State of Andhra Pradesh. The company belongs to GMR group. The distillery has implemented ISO-9001:2000: system.

The sugar division of the GMR Industries Ltd. (GIDL) owns a distillery with a capacity of 40 KLPD. The raw material to the distillery is molasses from the sugar plant. The major products from the distillery are Rectified Spirit (RS), Extra Neutral Alcohol (ENA) and Ethanol. The plant has modern Molecular Sieve Dehydration System. The plant is having zero pollution discharge.

The Spent-Wash generated from the distillery is high in Bio-chemical Oxygen Demand (BOD)/Chemical Oxygen Demand (COD) content. The approx. quantity of Spent-Wash generated from the process is ~400 m3 per day. The BOD level of the Spent-Wash is in the range 55000-60000 mg/l and the COD is in the range of 130000-150000 mg/l. As per the norms of State Pollution Control Board and Central pollution Control Board (CPCB) in India this high BOD/COD Spent-Wash can not be discharged without proper treatment. The limit of BOD of the Spent-Wash for disposal in surface water is 30 mg/l and for disposal on land is 100 mg/l.

In normal course distilleries in India adopt open lagoons treatment system for meeting the pollution control standards of BOD/COD of the Spent-Wash before its discharge. But in open lagoon system Methane, a potent GHG, is generated due to the anaerobic conditions which escape into atmosphere and there is no control or capturing involved. This project activity from GIDL entails treatment of this high BOD/COD Spent-Wash anaerobically in a closed digester and capturing the Methane generated in a controlled manner. The Methane captured is combusted in a boiler for steam generation and further to generate power through a turbo-generator. The project activity also includes combustion of other GHG natural biomass residue fuels such as rice-husk to supplement biogas fuel in the boiler. The capacity of the power generation plant is ~1.0 MW.

b. Technical Description of Project activity:

Location details:

The plant is located at the distillery unit of GIDL (Sugar Division) at village Sankili of Regidi Mandal of Srikakulam District in Andhra Pradesh, India. The plant site is about 142 km from the nearest airport of Visakhapatnam on National Highway NH-5. The geographic location in which the project activity is located is depicted in the map below:


INDIA
States and Union Territories
ANDHRA PRADES
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Districts of
Andhra Pradesh
Srikakulam
Vishakhapattana
Bay of Bengal
State Capital
State Boundary
District Boundary
District Headquarter
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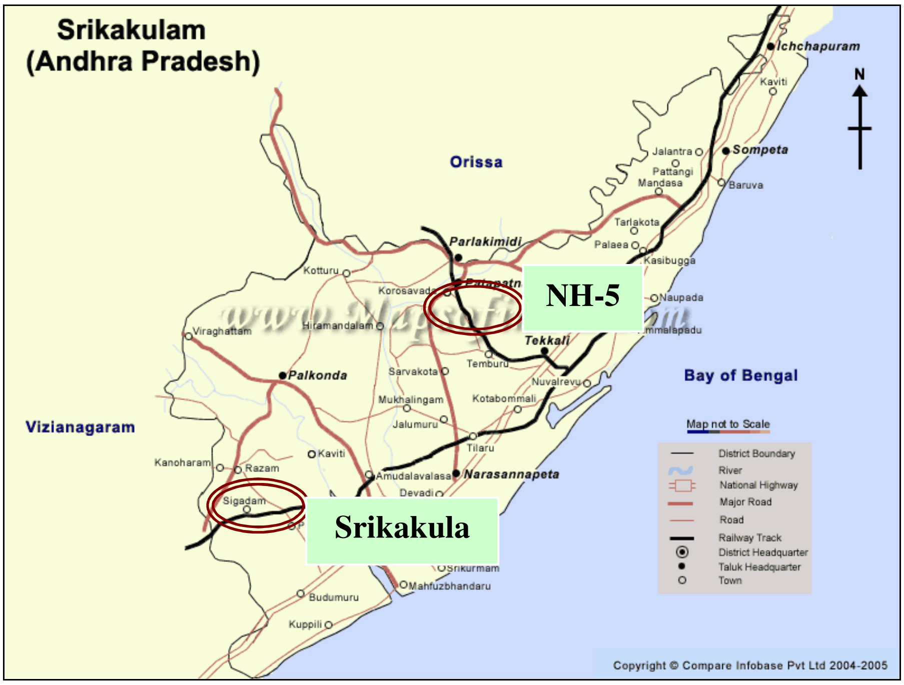

Technical Details:

Turbine Specification:

Steam turbine Model	PRSB 150
Inlet Steam pr.	43 ata
Inlet Steam Temp.	425 Deg C
Exhaust Steam Pr.	4 ata
Max. Steam flow	10.5 TPH
Turbine Rated Speed	8142 RPM
Rated Power	1000 kW
No of stages	05

Boiler Specification:

Make	Cheema Boilers ltd.
Capacity	10.5 TPH
Boiler Type	Power Pack-FBC
Superheated steam pr.	44 kg/cm2
Superheated steam temp.	430 +- 5 Deg C

ESP:

Make	Thermax Ltd.

Model	SC-9-16-16G-(3X1.25)-1.2P
Number of fields	3

5. Baseline Methodology

The project activity helps in GHG emission reduction in two ways-

1. Methane emission reduction through its controlled recovery in an anaerobic digestion plant
2. Reduction of emissions from fossil fuel based grid power by biogas and other biomass combustion in power generation plant

The project is a small scale CDM project activity and is based on Appendix B (Version No. 07 dated 28 November 2005) of the simplified modalities and procedures for small-scale CDM project activities. The project activity conforms to the following categories-

Category	Technology/ measure
TYPE IIIH: Methane Recovery in Wastewater Treatment Reference: version 1, Scope 13, 15; dated 03 March 2006	Comprises Methane recovery and combustion from waste water treatment facilities.
TYPE ID: Grid connected renewable electricity generation Reference: Version 8, Scope 1; dated 03 March 2006	Comprises renewable energy generation units that displaces electricity based on at least fossil fuel fired generating stations.

Estimation of Grid Emission factor has been done ex ante in PDD. The GEF calculation is done in Appendix -16.

6. Monitoring Methodology and Plan

The project is a small scale CDM project activity and is based on Appendix B (Version No. 07 dated 28 November 2005) of the simplified modalities and procedures for small-scale CDM project activities. The project activity conforms to the following categories-

Project Category	Criteria
TYPE IIIH : Methane Recovery in Wastewater Treatment	Comprises Methane recovery from Spent-Wash treatment facilities.
TYPE ID : Grid connected renewable electricity generation	Comprises renewable energy generation units that displaces electricity based on fossil fuel fired generating stations

6.1 The data being monitored as a part of project activity are as follows:

ID number	Data Source	Data variable	Data unit	Measured (m), calculated © or estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	For how long is archived data to be kept?	Comment	Reference
1.1	Plant Data	Flow of Spent-Wash in digester	m3	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -1
1.2	Lab test data	Chemical Oxygen Demand of untreated Spent-Wash into the digester	mg/l	*e*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*	*Standard "Reflux method" is used for estimation of COD of spent wash following Central Pollution Control Board norms*	Appendix -2
1.3	Lab test data	Chemical Oxygen Demand of treated water from digester	mg/l	*e*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*	*Standard "Reflux method" is used for estimation of COD of treated water following Central Pollution Control Board norms*	Appendix -3

1.4	Plant data	Biogas flow into boiler	m3	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -4
1.5	Lab test data	%CH4, Volumetric content of Methane in biogas	%	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*	*Methane concentration in biogas is measured using "Gas Chromatograph-Thermal Coductivity Detector"*	Appendix -5
1.6	Plant data	Pressure of biogas	mm. WC	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -6
1.7	Plant data	Temp. of biogas	Deg C	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		
1.8	Plant data	Gross Electricity generated in the power plant	kWh	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -7
1.9	Plant data	Auxiliary Electricity Consumption	kWh	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -8
1.10	Plant data	Net electricity generation	kWh	*c*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -9
1.11	Plant data	Quantity of fossil fuel i combusted in boiler	Tonnes	*m*	*Monthly*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -10
1.12	Lab test data	Calorific value of fossil fuel i combusted	kcal/ kg	*e*	*Monthly*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -11
1.13	Plant data	Power consumed in equipment in digester plant	kWh	*m*	*Daily*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -12

1.14	Plant data	Quantity of digester solid residues generated	tonnes	*m*	*Monthly*	*100%*	*paper*	*Credit period + 2 yrs*		Appendix -13
1.15	Plant data	Quantity of digester solid residue treated by composting	tonnes	*m*	*Monthly*	*100%*	*paper*	*Credit period + 2 yrs*	*Total quantity generated of solid residues in digester goes to composting plant*	Appendix -14
1.16	Plant data/ IPCC default values	Coefficient of emission for fossil fuel i combusted in boiler	tCO_2e/ tonne	*c*	*Monthly*	*100%*	*paper*	*Credit period + 2 yrs*	*Refer Section E.1.1 for detail formula*	Appendix -15

6.2 QA/QC Procedures being undertaken for data monitoring

Data *(Indicate table and ID number e.g. 3.-1.; 3.2.)*	Uncertainty level of data (High/Medium/Low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
Table D.3 (ID numbers from 1.1, 1.4, 1.6, 1.7	Low	The data will be collected as part of normal plant level operations. QA/QC requirements consist of cross- checking these with other internal company report.
Table D.3 (ID numbers from 1.2, 1.3	Low	Data are estimated using standard "Reflux method" as per Central Pollution Control Board (CPCB), Government of India norms.
Table D.3 (ID number 1.5	Low	Data is measured using "Gas Chromatograph –Thermal Conductivity Detector" method.
Table D.3 (ID numbers from 1.8- 1.10, 1.11, 1.13	Low	Data is monitored as part of power plant operation and logs are maintained on daily basis; meters are calibrated as per predefined calibration program
Table D.3 (ID number 1.12	Low	Fuel calorific value is lab tested of each stock and a record is maintained to this effect
Table D.3 (ID numbers from 1.14- 1.15	Low	Total solid residues from digester are sent to composting plant. A record for residues generated and sent to compost plant is maintained
Table D.3 (ID numbers 1.16	Low	Data is calculated based on NCV and IPCC default values for emission factor and oxidation factor for fossil fuels

GIDL's is an ISO-9001:2000 certified plant and it has well defined monitoring, calibration and recording procedures. Calibration of instruments is carried out as per predefined calibration plan.

7. GHG Calculations

The GHG calculation for this project is divided in two parts, as per the applicability of methodology.

A. For Methane Avoidance / Spent wash Treatment Part

As per the methodology AMS IIIH, the emission reductions for the methane avoidance are calculated as

$ER_y = BE_y – (PE_y + L_y)$

BE_y = Baseline emissions for spent wash treatment part
PE_y = Project emissions for spent wash treatment part
L_y = Leakage for spent wash treatment part

a) Calculation of BE_y i.e. baseline emissions for methane avoidance

BE_y = (Biogas flow into boiler) * (% CH4, Volumetric content of Methane in biogas) * (Methane Density) * GWP_CH4 / 1000

Variable	Value	Reference
Biogas flow into boiler (m^3)	Tabulated in Appendix	Appendix - 4
% CH4, Volumetric content of Methane in biogas (%)	Tabulated in Appendix	Appendix – 5
Density of Methane	Tabulated in Appendix	Appendix – 6 [1]
Global Warming Potential of CH4	21	

BE_y (spent wash treatment) for the six months:

BE_y (t CO2)	
Month	Value
October	1758.6
November	4466.0
December	4456.7
January	4777.3
February	4657.8
March	4340.2
Total	**24456.5**

b) Calculate PE_y i.e. Project emissions for Methane Avoidance

Power Consumption in digester plant

PE_y (Digester Plant) = (Power Consumption in digester plant) * (GEF) / 1000

Variable	Value	Reference
Power Consumption in digester plant / equipment (KWh)	Tabulated in Appendix	Appendix – 12
GEF (t CO2/MWh)	0.845	Appendix - 16

PE_y (spent wash treatment) for six months:

PE_y (t CO2)	
Month	Value
October	11.7
November	18.8
December	24.3
January	22.7
February	17.8
March	12.9
Total	**108.3**

[1] 0.68 kg/m^3 density is for STP i.e. atmospheric pressure and ambient temperature of 15° C. Temperature and pressure values are monitored to find density at actual temperature and pressure

http://encyclopedia.airliquide.com/Encyclopedia.asp?GasID=41#GeneralData

c) Calculate L_y i.e. Project Leakages

In this case the leakages are already taken into account, since methane avoidance is taken for only the methane going into boiler.

B. For Power Generation

This calculation is based on AMS ID

$ER_y = BE_y – (PE_y + L_y)$

a) BE_y (Power Generation) = (Gross Electricity Generated in Power Plant) * GEF /1000

Variable	Value	Reference
Gross Power generation in Power Plant (KWh)	Tabulated in Appendix	Appendix – 7
GEF (t CO2/MWh)	0.845	Appendix - 16

BE_y (power generation) for the six months:

BE_y (t CO2)	
Month	**Value**
October	234.9
November	434.2
December	404.8
January	155.1
February	342.9
March	336.0
Total	**1907.9**

b) PE_y (Combustion Process) = (Power Consumption in combustion process) * (GEF) / 1000

Variable	Value	Reference
Power Consumption in combustion process (KWh)[2]	Tabulated in Appendix	Appendix – 8
GEF (t CO2/MWh)	0.845	Appendix – 16

PE_y (power generation) for six months:

PE_y (t CO2)

[2] This power accounts for all the auxiliary consumption, also in situations when there is no gross generation.

Month	Value
October	56.9
November	84.9
December	90.5
January	85.1
February	84.4
March	83.9
Total	**485.6**

c) L_y (Fossil fuel combustion) = (fossil fuel consumption) * (Net calorific value of fossil fuel) * (IPCC default oxidation factor) * (Emission factor for sub-bituminous coal) * 4.187 / 1000000

Variable	Value	Reference
Quantity of fossil fuel combusted (tonnes)	Tabulated in Appendix	Appendix –10
NCV of Fossil fuel	4514	IPCC default
Oxidation factor	0.98	IPCC default value
Emission factor for sub-bituminous	96.1 tCO2 / TJ	IPCC default value

Rice husk consumption for power generation was monitored as part of standard procedures of plant, though not a part of monitoring plan are as below:

Rice Husk Consumption	
Month	**Value (tonnes)**
October	Nil
November	Nil
December	149.0
January	160.2
February	195.0
March	330.0
Total	**834.3**

L_y (power generation) for six months:

L_y (t CO2)	
Month	**Value**
October	1027.0
November	1717.2
December	1656.8
January	302.0
February	324.0
March	0.0
Total	**5027.0**

Emission reductions can be summarized as below:

tCO_2	Baseline Emissions		Project Emissions			Emission Reductions
Month	Methane Avoidance	Power Generation	Power Consumption in treatment process	Power Consumption in combustion process	Fossil fuel Combustion	
October	1758.6	234.9	11.7	56.9	1027.0	**897.9**
November	4466.02	434.2	18.8	84.9	1717.2	**3079.4**
December	4456.7	404.8	24.3	90.5	1656.8	**3089.8**
January	4777.3	155.1	22.7	85.1	302.0	**4522.6**
February	4657.8	342.9	17.8	84.4	324.0	**4574.5**
March	4340.2	336.0	12.9	83.9	0.0	**4579.3**
Total						**20743.5**

Appendix – 1

Flow of Spent Wash in digester

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	287	138	385	354	402
2	0	313	0	394	370	412
3	0	318	89	377	387	384
4	0	347	253	428	363	412
5	0	398	415	403	404	408
6	0	412	424	404	410	402
7	0	422	452	405	338	432
8	0	396	413	406	347	421
9	0	377	433	412	338	384
10	0	435	444	388	372	432
11	0	397	419	420	363	418
12	287	404	418	387	385	408
13	233	367	448	388	371	420
14	276	313	407	343	361	420
15	303	373	409	400	410	426
16	288	420	400	405	374	420
17	336	464	438	377	414	430
18	360	415	457	83	408	420
19	304	421	426	0	408	410
20	253	388	411	340	410	419
21	324	431	473	404	420	420
22	288	408	401	420	411	390
23	354	466	428	397	408	384
24	315	364	432	397	432	306
25	196	417	426	362	408	394
26	0	423	451	389	420	382
27	0	408	460	394	420	378
28	0	380	389	390	384	120
29	0	363	441	415	-	0
30	0	377	356	387	-	0
31	0	-	379	374	-	0

Appendix – 2

Chemical Oxygen Demand of untreated Spent-Wash into the digester (mg/l)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	132000	105000	130000	135000	123000
2	0	128000	0	129000	130000	120000
3	0	126000	80000	135000	130000	125000
4	0	120000	110000	125000	135000	120000
5	0	120000	110000	128000	122000	120000
6	0	118000	115000	128000	125000	123000
7	0	112000	110000	129000	135000	115000
8	0	110000	115000	128000	140000	120000
9	0	122000	110000	127000	140000	130000
10	0	112000	110000	130000	130000	120000
11	100000	120000	120000	123000	135000	120000
12	125000	120000	125000	120000	130000	122000
13	130000	124000	125000	126000	135000	118000
14	130000	130000	130000	120000	135000	120000
15	135000	125000	125000	126000	121000	118000
16	125000	115000	125000	128000	123000	115000
17	120000	110000	120000	132000	120000	120000
18	130000	115000	118000	135000	123000	114000
19	135000	115000	120000	0	124000	115000
20	126000	120000	125000	95000	122000	125000
21	133000	110000	115000	120000	120000	123000
22	120000	115000	125000	110000	122000	125000
23	127000	100000	120000	123000	123000	125000
24	120000	130000	120000	127000	118000	110000
25	0	118000	120000	135000	121000	123000
26	0	107000	115000	129000	120000	120000
27	0	115000	115000	129000	120000	115000
28	0	130000	125000	129000	125000	115000
29	0	135000	120000	123000	-	0
30	0	132000	135000	129000	-	0
31	0	-	130000	120000	-	0

Appendix – 3

Chemical Oxygen Demand of treated water from digester (mg/l)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	35000	36000	35000	35000	36000
2	0	36000	0	37000	36000	37000
3	0	36000	36000	35000	37000	35000
4	0	36000	36000	37000	37000	35000
5	0	36000	37000	36000	36000	35000
6	0	37000	40000	37000	37000	35000
7	0	40000	39000	39000	35000	34000
8	0	40000	37000	37000	36000	35000
9	0	39000	38000	37000	36000	37000
10	0	39000	39000	35000	36000	36000
11	40000	38000	39000	37000	37000	37000
12	36000	40000	38000	35000	38000	36000
13	36000	40000	39000	35000	38000	35000
14	35000	37000	40000	37000	35000	36000
15	35000	39000	39000	36000	35000	36000
16	36000	38000	38000	38000	35000	34000
17	36000	38000	38000	35000	35000	35000
18	36000	38000	40000	35000	36000	34000
19	34000	40000	38000	0	37000	34000
20	36000	38000	36000	36000	35000	37000
21	34000	39000	40000	38000	36000	36000
22	37000	39000	39000	36000	35000	35000
23	37000	36000	37000	36000	36000	36000
24	40000	38000	37000	37000	35000	34000
25	0	40000	36000	36000	35000	35000
26	0	40000	36000	38000	35000	35000
27	0	40000	37000	36000	35000	35000
28	0	40000	36000	37000	35000	35000
29	0	39000	37000	36000	-	0
30	0	40000	37000	35000	-	0
31	0	0	39000	36000	-	0

Appendix – 4

Biogas Flow into Boiler (m^3)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	15295	5306	19648	19648	18866
2	0	15549	0	19347	18760	17992
3	0	15450	2176	20020	19030	18736
4	0	15714	10432	19995	19178	18792
5	0	17962	17365	19995	18643	18420
6	0	17639	17125	19636	18985	18940
7	0	16518	17065	19342	18873	18551
8	0	15662	17146	19827	19079	18928
9	0	17240	16785	19585	18817	19329
10	0	17540	16778	19450	18840	19010
11	9122	17112	18236	19255	18950	18727
12	11578	17219	19295	17606	18863	18621
13	13861	16878	19399	18768	19082	18967
14	16599	16214	19605	15044	19260	18920
15	16234	17256	18829	19060	18820	18925
16	16028	17716	18605	19255	17500	18430
17	15824	17964	19083	19472	18555	19318
18	15892	17652	19018	6122	18880	18337
19	15671	17154	18704	0	18879	17773
20	16026	17607	19518	10400	19048	19553
21	15822	16775	18837	17520	18800	19449
22	15529	16924	18404	16450	19154	18775
23	15505	16661	18923	18289	18846	18102
24	8360	17721	19192	19061	19018	12863
25	0	17484	19284	19360	18688	18325
26	0	15008	18990	18820	19140	17572
27	0	16340	18928	19540	18858	15981
28	0	18414	18602	19120	18840	5118
29	0	19059	18306	19278	-	0
30	0	18749	18466	19181	-	0
31	236		18300	16883	-	0

Appendix – 5

%CH4, Volumetric content of Methane in biogas

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	61.41	62.52	61.14	63.2	62.88
2	0	62.36	0	61.89	61.75	61.25
3	0	62.36	62.36	61.24	60.2	62.05
4	0	62.24	61.31	62.56	63.38	62.4
5	0	61.31	60.38	60.3	62.63	62.15
6	0	61.22	61.55	61.75	61.1	61.14
7	0	63.41	61.95	61.56	60.38	64.52
8	0	63.32	61.08	61.52	61.38	62.45
9	0	62.38	60.11	61.16	61.38	62.16
10	0	62.45	60.38	61.75	63.52	61.76
11	61.24	61.4	61.11	61.63	62.36	63.36
12	62.36	63.36	61.55	61.03	63.36	63.31
13	62.14	61.41	60.43	61.26	63.63	63.75
14	63.75	62.15	60.16	62.16	62.38	63.22
15	61.41	61.75	61.21	62.52	63.55	61.99
16	61.83	62.36	60.36	61.75	64.38	63.46
17	62.85	61.32	60.38	61.96	64.56	63.8
18	61.03	62.01	61.55	62.11	63.85	62.21
19	61.05	63.2	61.33	0	63.15	62.17
20	62.85	61.65	61.38	62.89	63.75	63.46
21	63.24	62.36	61.99	63.39	64.01	61.01
22	62.01	62.01	61.38	62.55	63.1	63.05
23	62.75	61.75	61.31	62.35	64.75	62.66
24	62.85	61.15	60.43	62.11	61.75	61.63
25	0	62.11	61.05	62.49	65.23	62.41
26	0	62.16	61.38	63.11	62.4	61.85
27	0	63.36	61.31	62.35	60.65	60.73
28	0	62.11	61.86	62.55	63.85	60.73
29	0	62.15	62.36	63.39	-	0
30	0	62.36	61.14	63.5	-	0
31	61.36		61.15	63.5	-	0

Appendix – 6

Pressure of Biogas (mm of water column)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	650	600	800	800	750
2	0	650	0	800	750	700
3	0	650	200	800	750	750
4	0	650	400	800	750	750
5	0	750	700	800	700	700
6	0	700	700	800	700	750
7	0	700	700	800	700	750
8	0	650	700	800	750	750
9	0	700	700	800	700	750
10	0	750	700	800	700	750
11	350	700	750	800	700	750
12	450	700	800	700	700	750
13	550	700	800	750	750	750
14	700	700	800	600	750	750
15	650	700	750	750	750	750
16	650	750	750	800	650	700
17	650	750	750	800	750	750
18	650	750	750	250	750	700
19	650	710	750	0	750	700
20	650	750	800	400	750	750
21	650	700	750	700	700	750
22	650	700	750	650	750	750
23	650	700	750	750	700	700
24	700	750	800	750	750	500
25	0	750	800	800	700	700
26	0	650	750	750	750	700
27	0	700	750	800	700	600
28	0	750	750	750	700	650
29	0	800	750	800	-	0
30	0	800	750	750	-	0
31	0		750	700	-	0

Temperature of Biogas (Deg Celsius)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	39	40	40	40	43
2	0	39	0	40	41	43
3	0	38	39	40	41	44
4	0	39	39	40	40	43
5	0	40	40	40	41	43
6	0	40	39	40	40	44
7	0	39	40	40	40	44
8	0	39	40	40	40	45
9	0	40	39	40	40	45
10	0	40	39	40	41	44
11	39	39	39	40	40	45
12	39	39	40	40	41	45
13	40	39	40	40	41	45
14	40	39	40	39	41	46
15	39	40	39	40	40	45
16	39	39	40	40	40	44
17	39	40	39	40	40	45
18	39	40	39	38	40	44
19	39	39	39	0	40	45
20	40	39	39	38	41	46
21	40	39	39	40	42	46
22	39	39	40	39	42	45
23	40	40	39	39	42	45
24	39	40	39	40	42	46
25	0	39	39	40	43	46
26	0	39	40	40	43	45
27	0	39	40	40	43	45
28	0	40	40	40	43	45
29	0	40	40	40	-	0
30	0	40	40	40	-	0
31	0		40	39	-	0

Density of Methane kg/cm^3 (calculated from pressure and temperature)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0.717	0.667	0.662	0.674	0.674	0.665
2	0.717	0.667	0.717	0.674	0.672	0.662
3	0.717	0.669	0.640	0.674	0.672	0.663
4	0.717	0.667	0.652	0.674	0.674	0.665
5	0.717	0.671	0.668	0.674	0.672	0.662
6	0.717	0.668	0.670	0.674	0.674	0.663
7	0.717	0.670	0.668	0.674	0.674	0.663
8	0.717	0.667	0.668	0.674	0.674	0.661
9	0.717	0.668	0.670	0.674	0.674	0.661
10	0.717	0.671	0.670	0.674	0.672	0.663
11	0.649	0.670	0.673	0.674	0.674	0.661
12	0.655	0.670	0.674	0.668	0.666	0.661
13	0.659	0.670	0.674	0.671	0.669	0.661
14	0.668	0.670	0.674	0.664	0.660	0.659
15	0.667	0.668	0.673	0.671	0.671	0.661
16	0.667	0.673	0.671	0.674	0.674	0.660
17	0.667	0.671	0.673	0.674	0.674	0.661
18	0.667	0.671	0.673	0.645	0.641	0.660
19	0.667	0.671	0.673	0.717	0.647	0.658
20	0.665	0.673	0.676	0.654	0.648	0.659
21	0.665	0.670	0.673	0.668	0.664	0.659
22	0.667	0.670	0.671	0.667	0.661	0.661
23	0.665	0.668	0.673	0.673	0.667	0.658
24	0.670	0.671	0.676	0.671	0.667	0.644
25	0.717	0.673	0.676	0.674	0.668	0.656
26	0.717	0.667	0.671	0.671	0.665	0.658
27	0.717	0.670	0.671	0.674	0.668	0.652
28	0.717	0.671	0.671	0.671	0.665	0.655
29	0.717	0.674	0.671	0.674	-	0.717
30	0.717	0.674	0.671	0.671	-	0.717
31	0.717		0.671	0.670	-	0.717

Appendix – 7

Gross Electricity Generation in Power Plant (KWh)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	17050	5355	15230	14384	14133
2	0	17543	0	15399	15718	6785
3	0	17442	6081	15452	14582	11922
4	0	17538	16986	15545	14707	14066
5	1423	17684	17371	15090	14736	14179
6	0	17688	16953	15554	17424	14150
7	0	17684	16950	15557	17291	14719
8	13657	16973	18728	15661	17490	15468
9	12406	16755	18815	15548	16716	15002
10	1498	16804	18203	15523	13869	15199
11	16476	16583	17968	15439	14588	15202
12	18041	16767	18615	9321	15183	15611
13	18993	16987	17651	0	15357	16163
14	18436	17124	18780	0	15450	16621
15	18549	17345	18259	0	15844	16186
16	18447	16794	17552	0	8523	16439
17	18125	17166	15543	0	6600	15385
18	18004	14478	15355	0	14581	14135
19	19467	17414	17331	0	14679	14135
20	19501	16955	16896	0	14559	14284
21	18542	17184	16197	0	14135	14411
22	18522	17376	15409	0	14239	14365
23	18092	17261	15043	0	14088	14112
24	9820	17567	15135	0	14289	11263
25	0	17432	15556	0	14090	14650
26	0	17295	15484	0	14363	16144
27	0	16998	15403	0	14040	14415
28	0	17547	15152	0	14239	3459
29	0	17424	15503	0	-	0
30	0	17032	15368	0	-	0
31	0		15418	4197	-	4990

Appendix – 8

Auxiliary Electricity Consumption (KWh)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	230	3308	2442	3761	3333	3461
2	888	3427	941	3608	3576	3284
3	397	3356	2078	3569	3616	3350
4	1468	3342	3591	3638	3546	3465
5	1193	3316	3668	3570	3430	3435
6	334	3276	3647	3679	3573	3456
7	575	3289	3456	3659	3621	3437
8	3339	3307	3692	3663	3665	3464
9	3147	3344	3744	3609	3665	3508
10	1878	3358	3608	3686	3523	3521
11	3346	3303	3596	3630	3568	3542
12	3476	3425	3530	3652	3719	4190
13	3588	3337	3646	3547	3767	3566
14	3509	3372	3674	2939	3865	3437
15	3551	3387	3659	3175	4063	3377
16	3491	3326	3747	3226	3416	3417
17	3473	3384	3666	3080	3508	3433
18	3478	3271	3568	2276	3534	3401
19	3418	3327	3637	1214	3459	3312
20	3555	3388	3734	3033	3447	3485
21	3312	3323	3629	3263	3484	3501
22	3416	3361	3694	3096	3465	3456
23	3444	3360	3635	3116	3468	3267
24	2497	3371	3585	3135	3527	2922
25	1507	3416	3557	3044	3514	3401
26	818	3344	3584	3100	3484	3375
27	636	3337	3548	3129	3549	3331
28	659	3387	3551	3152	3453	1730
29	636	3389	3662	3081	-	940
30	729	3321	3663	3103	-	1022
31	1320		3662	3250	-	2813

Appendix – 9

Net Electricity Generation (KWh)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	0	13742	2913	11469	11051	10672
2	0	14116	0	11791	12142	3501
3	0	14086	4003	11883	10966	8572
4	0	14196	13395	11907	11161	10601
5	230	14368	13703	11520	11306	10744
6	0	14412	13306	11875	13851	10694
7	0	14395	13494	11898	13670	11282
8	10318	13666	15036	11998	13825	12004
9	9259	13411	15071	11939	13051	11494
10	0	13446	14595	11837	10346	11678
11	13130	13280	14372	11809	11020	11660
12	14565	13342	15085	5669	11464	11421
13	15405	13650	14005	0	11590	12597
14	14927	13752	15106	0	11585	13184
15	14998	13958	14600	0	11781	12809
16	14956	13468	13805	0	5107	13022
17	14652	13782	11877	0	3092	11952
18	14526	11207	11787	0	11047	10734
19	16049	14087	13694	0	11220	10823
20	15946	13567	13162	0	11112	10799
21	15230	13861	12568	0	10651	10910
22	15106	14015	11715	0	10774	10909
23	14648	13901	11408	0	10620	10845
24	7323	14196	11550	0	10762	8341
25	0	14016	11999	0	10576	11249
26	0	13951	11900	0	10879	12769
27	0	13661	11855	0	10491	11084
28	0	14160	11601	0	10786	1729
29	0	14035	11841	0	-	0
30	0	13711	11705	0	-	0
31	0		11756	947	-	2177

Appendix – 10

Quantity of Fossil fuel burnt (tonnes)

Month	Oct	Nov	Dec	Jan	Feb	March
Quantity(t)	577	964.7	930.8	169.6	182	0

Appendix – 11

Calorific value of fossil fuel i combusted

Month	Oct	Nov	Dec	Jan	Feb	March
Quantity(t)	4514	4514	4514	4514	4514	4514

Appendix – 12

Power consumed in equipment in digester plant (KWh)

Date / Month	Oct	Nov	Dec	Jan	Feb	March
1	213	619	550	985	907	542
2	355	656	410	928	878	488
3	312	579	427	1134	878	598
4	293	559	648	1025	865	547
5	288	683	998	1063	870	518
6	295	657	966	1021	851	504
7	300	627	979	1046	873	504
8	320	544	1022	1052	851	515
9	441	648	1000	1021	831	556
10	297	746	1043	1028	818	522
11	531	732	962	1001	837	519
12	646	739	1049	940	809	688
13	687	750	967	920	804	613
14	618	665	979	772	845	634
15	639	726	1006	832	813	518
16	630	768	973	943	757	589
17	561	802	991	919	781	556
18	545	733	989	564	745	580
19	524	769	1035	309	683	464
20	607	808	988	1209	678	517
21	589	778	1034	46	648	525
22	590	798	912	767	645	488
23	528	811	910	782	628	472
24	400	801	917	814	564	412
25	348	901	927	792	557	591
26	412	817	956	816	585	543
27	391	758	973	807	557	590
28	417	863	1033	825	536	224
29	428	907	1055	960	-	124
30	316	980	1055	778	-	177
31	318		1051	783	-	182

Appendix – 13

Quantity of digester solid residues generated (in form of liquid) m^3

Month	Oct	Nov	Dec	Jan	Feb	March
Quantity(m^3)	4117	11704	11930	11474	10890	11054

Appendix – 14

Quantity of digester solid residue treated by composting (in form of liquid) m^3

Month	Oct	Nov	Dec	Jan	Feb	March
Quantity(m^3)	5255.8	6908.7	6100	6560	5926	6200

Appendix – 15

Coefficient of emission for fossil fuel i combusted in boiler (tCO2/tonne) (IPCC default value taken)

Month	Oct	Nov	Dec	Jan	Feb	March
	1.78	1.78	1.78	1.78	1.78	1.78

Appendix -16

Estimation of baseline emissions

Baseline scenario is that the electricity generated by the project would otherwise have been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations (for SR Grid) described below.

Step 2.1: Calculate the Operating Margin emission factor ($EF_{OM,y}$)

ACM0002, version 05 dated 03 March 2006, suggested following methods to calculate the Operating Margin emission factor(s) ($EF_{OM,y}$):

(a) Simple OM, or

(b) Simple adjusted OM, or

(c) Dispatch Data Analysis OM, or

(d) Average OM.

As per the approved methodology ACM0002 Dispatch data analysis should be the first methodological choice. However due to lack of data availability 'Dispatch Data Analysis' is not selected for the project activity.

The Simple adjusted OM and Average OM methods are applicable to project activities connected to the project electricity system (grid) where the low-cost/must run resources constitute more than 50% of the total grid generation.

'Simple OM' method is applicable to project activity connected to the project electricity system (grid) where the low-cost/must run resources constitute less than 50% of the total grid generation in 1) average of the five most recent years, or 2) based on long-term normal for hydroelectricity production.

The low-cost/must run resources contribute to less than 50% of total power in the grid hence 'Simple OM' option has been chosen.

Generation Mix of Power in Southern Grid

Type	2002-03	2003-04	2004-05
Thermal	93350.1	96664.0	97964.3
Diesel	4457.0	3225.0	2370.1
Gas	15138.0	16183.0	12276.6
Total (Thermal + Gas)	**112945.1**	**116072.0**	**112611.1**
Wind*	1577.3	2055.7	1270.7
Hydro	18167.8	17317.0	25280.4
Nuclear	4390.0	4700.0	4406.7
Low cost/Must run	**24135.1**	**24072.7**	**30957.8**
Total	**137080.1**	**140144.7**	**143568.8**
% of Low cost/must run	**18%**	**17%**	**22%**

Unit: Million Units
Source: www.cea.nic.in

The Simple OM emission factor ($EF_{OM,simple,y}$) is calculated as the generation-weighted average emissions per electricity unit (tCO_2/MU) of all generating sources serving the project electricity system, not including low-operating cost and must-run power plants.

The Simple OM emission factor can be calculated using either of the two following data vintages for years(s) y:

- A 3-year average, based on the most recent statistics available at the time of PDD submission, or
- The year in which project generation occurs, if $EF_{OM,y}$ is updated based on ex post monitoring.

The project activity uses the OM emission factor as per the 3-year average of Simple OM calculated based on the most recent statistics available at the time of PDD submission.

Source	MoU	OM (2002-03)	OM (2003-04)	OM (2004-05)
Year-wise OM	tCO2/ MWh	0.952	0.978	0.992
OM	tCO2/ MWh		0.974	

Emissions due to imports from other grids into the southern grid have been considered as "0 tCO2/MWh". This is conservative.

Step 2.2: Calculate the Build Margin emission factor ($EF_{BM,y}$)

As per the methodology the Build Margin emission factor ($EF_{BM,y}$) is calculated as the generation-weighted average emission factor (tCO_2/MU) of a sample of power plants. The project activity calculates the Build Margin emission factor $EF_{BM,y}$ ex ante based on the most recent information available on plants already built for sample group m at the time of PDD submission.

The sample group *m* consists of either:

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

As per the baseline information data the option (b) comprises the larger annual generation. Therefore for the project activity the sample group m consists of power plants capacity additions in the electricity system that comprise 20% of the system generation (in MU) and that have been built most recently. Power plant capacity additions registered as CDM project activities are excluded from the sample group.

Power Plants considered for Build Margin (BM) estimation:

Type	State	Station	Capacity (MW)	Commissioning Date
Hydro	AP	Mini Hydro	30.0	01.12.2005
Hydro	Karnataka	Narayanpur	6.6	01.12.2005
Hydro	Kerala	Other Hydro	5.0	01.12.2005
Hydro	Kerala	Malampuzha	2.5	01.12.2005
Hydro	Karnataka	Almattidam 6	55.0	10.08.2005
Hydro	Karnataka	Almattidam 5	55.0	06.07.2005
Hydro	Karnataka	Almattidam 4	55	26.03.2005
Hydro	Karnataka	Almattidam 3	55	13.01.2005
Hydro	Karnataka	Almattidam 2	55	04.11.2004
Hydro	Kerala	Malankara	10.5	30.05.2004

Gas	Tamilnadu	Kuttalam	36	30.03.2004
Hydro	Karnataka	Almattidam 1	15	26.03.2004
Hydro	Kerala	Chembukadavu	6.5	30.12.2003
Hydro	Kerala	Urumi	6.2	30.12.2003
Gas	Tamilnadu	Kuttalam	64	30.11.2003
Thermal	Tamilnadu	NLC TS I extension	420	15.09.2003
Hydro	AP	Srisailam Left 6	150.0	04.09.2003
Hydro	Karnataka	Shahpur	1.4	01.08.2003
Hydro	AP	Srisailam Left 5	150.0	28.03.2003
Gas	Tamilnadu	Valuthur	94	13.03.2003
Thermal	Tamilnadu	Neyvelli Zero	250	16.12.2002
Thermal	Karnataka	Raichur TPS	210	10.12.2002
Hydro	AP	Srisailam Left 4	150.0	29.11.2002
Thermal	AP	Simhadri	500	15.08.2002
Hydro	AP	Srisailam Left 3	150.0	19.04.2002
Gas	AP	LANCO- Kondapalli	355	01.03.2002
Diesel	AP	LVS power	36.8	15.01.2002
Thermal	AP	Simhadri	500	15.01.2002
Gas	AP	BSES- Peddapuram	220	30.11.2001
Hydro	AP	Srisailam Left 2	150.0	12.11.2001
Diesel	Tamilnadu	Samayanallur DEPP	106	22.09.2001
Diesel	Tamilnadu	Samalpatti DEPP	105.7	15.07.2001
Diesel	Karnataka	Belgaum	81.3	01.07.2001
Hydro	Karnataka	Madhavmantrii	3	01.07.2001
Hydro	Kerala	Kuthungal	21	01.07.2001
Gas	Karnataka	Tanir Bavi	220	15.05.2001
Hydro	Karnataka	Gerusuppa	240	01.05.2001
Hydro	AP	Srisailam Left 1	150.0	26.04.2001
Gas	Tamilnadu	Pillai Perumal Nallur GTPP	330.5	26.04.2001
Diesel	Kerala	Kasargode	21.84	15.03.2001
Hydro	Kerala	Kuttiadi	50	27.01.2001
Nuclear	Karnataka	Kaiga 1	220	16.11.2000
Gas	Tamilnadu	Kovilkalapai	108	30.09.2000
Hydro	Tamilnadu	Mukurthy Mini	0.7	18.08.2000
Diesel	Karnataka	Bellay	25.2	15.05.2000
Hydro	Tamilnadu	Parsons Valley	30	29.03.2000
Hydro	Tamilnadu	Thirumurthy Mini	1.95	20.03.2000
Nuclear	Karnataka	Kaiga 2	220	16.03.2000
Hydro	AP	Singur	15.0	31.03.2000
Thermal	Karnataka	Torangulu Steam	130	15.12.1999
Thermal	Karnataka	Torangulu Steam	130	15.12.1999
Hydro	Kerala	Kakkad	50	14.10.1999
Gas	Kerala	Kayamkulam GT3	129.2	01.10.1999
Hydro	Karnataka	Kodasalli 3	40	28.08.1999
Hydro	Karnataka	Rajankollur	2	01.08.1999
Hydro	Karnataka	Harangi	9	19.07.1999
Gas	Pondichery	PPCL GTG	32.5	25.05.1999
Hydro	Karnataka	Kadra 3	50	21.05.1999
Hydro	Karnataka	Kodasalli 2	40	20.04.1999
Hydro	Tamilnadu	Sathanur	7.5	30.03.1999
Diesel	Tamilnadu	GMR Vasavi DEPP	196	01.02.1999

Source	MoU	Thermal	Diesel	Gas	Hydro	Nuclear	Wind	
Gross Generation	MU	23929.8	1796.0	7339.4	3296.5	2926.3	1270.7	
Net Generation	MU	23096.9	1742.3	7252.9	3279.7	2575.1	1270.7	39217.6
Heat Rate	kcal/kWh	2490.0	2062.0	2000.0	0.0	0.0		
Fuel CV	kcal/kg	3820.0	10186.0	10350.0	0.0	0.0		
Fuel Consumption	Tonnes per annum	15598220.4	363572.7	1418241.5				
Total Emissions	tCO2/ annum	23495832.6	1137499.9	3430674.0				28064006.6
Emission Factor-BM	tCO2/ MWh	**0.716**						

Step 2.3: Calculate the Electricity Baseline Emission Factor ($EF_{electricity,\ y}$)

Electricity baseline emission factor is calculated as the weighted average of the Operating Margin emission factor (*EFOM,y*) and the Build Margin emission factor (*EFBM,y*) where the weights *wOM* and *wBM*, by default, are 50% (i.e., *wOM* = *wBM* = 0.5). This is presented in the table below.

Source	MoU	OM (2002-03)	OM (2003-04)	OM (2004-05)
Year-wise OM	tCO2/ MWh	0.952	0.978	0.992
OM	tCO2/ MWh	0.974		
BM	tCO2/ MWh	0.716		
Emission Factor-CM	tCO2/ MWh	**0.845**		