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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

>>
BHL Palia Kalan Project
16/01/2007
Version 3

A.2. Description of the project activity:

>>
The project activity is being undertaken by Bajaj Hindusthan Ltd at its 11,000 tonnes of cane per day (tcd) sugar factory. The project activity involves installing of a new power plant next to an existing power plant, at the sugar factory in Uttar Pradesh, India. The power plant will use biomass, bagasse, a renewable biomass material that is produced from the milling of cane to generate electricity for supply to the grid.

The existing power plant at the factory is made up of seven turbines, five of which are of 3MW capacity and the remaining turbines are of 2.5MW and 0.8MW capacity. All the turbines are manufactured by Triveni and are of back pressure type. The turbine generators are fed by five boilers, two of which are manufactured by Texmaco, having a capacity of 25TPH and 50TPH and operating at a pressure of 21 kg/cm^2 and 45 kg/cm^2 respectively. The other two boilers are manufactured by Walchand Nagar Industries, having a capacity of 70TPH and an operating pressure and temperature of 45 kg/cm^2 and 450^{o}C respectively. The remaining one boiler is manufactured by Thermax and is of 80TPH capacity and operates at a pressure and temperature of 45 kg/cm^2 and 450^{o}C respectively.

The project activity involves the installation of a new turbine manufactured by Triveni. The new turbine will be of 12MW capacity and is of condensing cum extraction type.

The electricity will be generated at 11kV and stepped up at the plant to 132kV to parallel with the grid at this level. It will be supplied to the grid via the 132kV Kheri sub-station which is located 5km from the plant.

There are five diesel generators on site two 400kVA and the other are 750kVA, 250kVA and 100kVA generating electricity at 415V. These units are only used in emergencies or during the off-season when electricity is not available from the plant.

The project makes a significant contribution to development as any rurally based industry in India provides an important source of direct employment in the surrounding area. Uttar Pradesh, where the plant is located, is one of the most populous states in India with 88% of the population located in rural areas[1]. Therefore the provision of direct employment will provide a much needed alternative to those situated in the locality of the plant. The factory currently employs about 803 people and it is expected to increase employment by about 30 people, a number of whom will be skilled boiler and turbine operators and engineers.

---

[1] www.censusindia.net

The factory currently serves about 45,697 farmers from 343 local villages and provides an important source of income for these farmers. The factory carries out significant extension services for the farmers, namely the:

- Provision of insecticide, pesticides and cane seed treatment at subsidised rates
- Educating farmers regarding scientific cultivation for better production of cane
- Introduction of drip irrigation system which has resulted in increased yield, better crop, reduced cost on fertilizers and saving on water by 70%
- Distribution of agricultural instruments for better harvesting of cane leading to increase in output by reducing wastage
- Providing new varieties of cane to the farmers to increase cane production
- Distribution of Bajaj Jaivik on subsidised rate to farmers to improve soil structure and decrease the usage of chemical fertilizers
- Provision of interest free loan to the farmers by the company

The factory installed hand pumps to provide fresh and clean water to the villagers. The factory has also undertaken desilting of *Nala*s and construction of a bridge over the Suheli river. This will help in dealing with the flooding situations that arise during the rainy season and periods of release of excess water from the Banbasa Dam. These steps will prevent water logging in cane fields and protect the adjoining Dudhwa National Park. The factory organises medical camps, food and cloth distribution in flooded areas on a regular basis. The factory also undertakes significant work in road and culvert construction in the surrounding areas.

The provision of electricity to the grid through the implementation of the project activity should strengthen the returns of the factory. No longer will the factory just be a manufacturer of sugar but it will also be a power producer and thus the higher returns associated with a broadening of its activities should filter back to those supplying the factory through the cane price.

Through the generation and supply of renewable electricity to the grid the project activity will have a direct environmental benefit. The combustion of renewable biomass has long term benefits related to climate change given that the alternative is a fossil fuel based generation system. Local pollution will also be reduced through the combustion of biomass relative to the alternative fossil fuels for the supply of electricity, especially in relation to NOx, SOx and ash which arise in coal based generation (ash content of bagasse is of the order of 3-4% whilst Indian coal typically has an ash content of greater than 35%).

A.3. Project participants:

>>

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	If Party wishes to be considered as a project participant
India (host)	Private entity: Bajaj Hindusthan Ltd	No
UK	Private entity: Agrinergy Ltd	No

The official contact for the project activity will be Bajaj Hindusthan Ltd, contact details as listed in Annex I.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

>>

A.4.1.1. Host Party(ies):

>>
India

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

>>
Uttar Pradesh

A.4.1.3. City/Town/Community etc:

>>
Village Palia Kalan, Tehsil Lakhimpur, District Lakhimpur Kheri

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

>>
The sugar factory is located on plots identified by the Khasara Numbers: 112, 129, 130, 132 and 78. The factory is located 75km from the district headquarter Lakhimpur Kheri on the state highway number 25 connecting the Dudhwa national park.
The geographical location of Lakhimpur Kheri[2] is latitude- 27-6 to 28.6 (North)and longitude- 80.34 to 81.30 (East).

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

>>
Category 1: Energy industries (renewable - / non - renewable sources)

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

>>
The technology employed is available in India and in the case of the project activity some of the technology is provided by local suppliers. The project activity involves the installation of a new turbine of 12MW capacity of condensing cum extraction type. The electricity will be generated at 11kV and stepped up at the plant to 132kV to parallel with the grid at this level. It will be supplied to the grid via the 132kV Kheri sub-station. The technologies employed are as per the industry norms and are in line with the consents from pollution control board and meet the environmental and safety guidelines.

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

>>

Year	Annual estimation of emission reductions in tonnes of CO_2e
2007	18,870

[2] As requested by DOE in the case of these data not available for the sugar factory.

http://www.answers.com/topic/lakhimpur-kheri

2008	26,229
2009	26,229
2010	26,229
2011	26,229
2012	26,229
2013	26,229
2014	26,229
2015	26,229
2016	26,229
Total estimated reductions (tonnes CO_2e)	**254,930**
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	25,493

A.4.5. Public funding of the project activity:

>>
The project has not received any public funding.

SECTION B. Application of a baseline and monitoring methodology

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

>>
The project activity follows the following methodology:
Version 04 of ACM0006

In line with the application of the methodology the project draws on element of the following tools and methodologies:
Version 03 of the tool for the demonstration and assessment of additionality
Version 06 of ACM0002

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

>>
The project activity involves the installation of a new biomass residue based power generation unit which will be operated next to an existing power generation capacity both of which will use the same type of biomass residue, namely bagasse (**power capacity expansion project**). The project activity takes place at an agro-industrial unit, a sugar factory, from which it will receive the biomass residue.

All the biomass used at the site qualifies under the definition of biomass residues as outlined in the methodology, i.e. the biomass residue is a by-product of agricultural activities and no other types of biomass residue will be used. In the case of the project the biomass residue will be bagasse, which is generated from the crushing of sugar cane.

The implementation of the project does not result in an increase in the processing capacity of the raw input or any other changes in the sugar manufacturing process. The installation of the power plant will not alter the crushing capacity of the sugar plant.

The biomass residue used by the project will not be stored for more than one year. Small quantities of biomass residue may be held over from one season to the next to be used as start up fuel but this would only imply storage from the end of the season to the start of the new season. The actual length of this will depend on the running hours of the plant but it is expected to be less than 6 months.

The biomass residue is not prepared prior to its use in the boilers, the bagasse is transferred from the crushing process directly to the boiler.

B.3. Description of the sources and gases included in the project boundary

>>

	Source	Gas	Included?	Justification/Explanation
Baseline	Grid electricity generation	CO_2	Yes	Main emission source
	Heat generation	CO_2	No	No emission reductions are claimed for heat generated by the project activity as under the baseline the same quantity of heat would be generated during the sugar crushing season

	Uncontrolled burning or decay of Surplus biomass.	CH_4	No	Not applicable under the selected baseline scenario, B1 is not a biomass baseline scenario
Project activity	On-site fossil fuel consumption due to the project activity	CO_2	No	No fossil fuel will be consumed at the project site
	Off-site transportation of biomass	CO_2	No	All biomass will be utilized from the sugar mill situated next to the project activity
	Combustion of biomass for electricity and/or heat generation	CH_4	No	Emissions from uncontrolled burning or decay of biomass are not included in the baseline scenario and these sources are therefore not accounted for in project activity emissions.

The project boundary includes the equipment installed for the operation of the power plant, the main elements of which are the boiler, turbine generator, condenser, water treatment plant, effluent treatment plant, electrostatic precipitator, step up plant/transformers, transmission lines and the Northern regional grid.

Fly ash is analysed in the context of the project boundary but it will be mainly used in composting at the plant site and disposed of in low lying areas in line with consents from local bodies. The point to note is that in the baseline scenario a far greater quantity of fly ash would be generated as Indian coal[3] has a much higher ash percentage than bagasse and this would have to be transported to the disposal site. The transport of bagasse to the boiler is via conveyor but this is a normal practise in any sugar mill and the boilers in the project activity are located within the sugar factory.

As the boundary for the determination of the grid carbon emission factor in India is not clearly defined we follow the guidance in the methodology, ACM0002. The DNA has to date not issued guidance on the delineation of grid boundaries and we therefore follow the guidance for the layered despatch systems and adopt a regional grid. The Indian electricity system is split into five regional grids, North, South, East, West and North East. The project activity falls under the Northern grid. and the CEF has been calculated for the northern grid as detailed in Annex 3.

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

>>
The determination of the baseline scenario requires us to consider the most conservative baselines for the generation of power, the generation of heat and the use of biomass.

There are six power baselines detailed in the methodology, namely:

P1 The proposed project activity not undertaken as a CDM

P2 The proposed project activity (installation of a power plant), fired with the same type of biomass residues but with a lower efficiency of electrical generation (e.g. an efficiency that is common practice in the relevant industry sector)

[3] http://www.coal.nic.in/

P3 The generation of power in an existing plant, on-site or nearby the project site, using only fossil fuels
P4 The generation of power in existing and/or new grid-connected power plants
P5 The continuation of power generation in an existing power plant, fired with the same type of biomass residues as (co-)fired in the project activity, and implementation of the project activity, not undertaken as a CDM project activity, at the end of the lifetime of the existing plant
P6 The continuation of power generation in an existing power plant, fired with the same type of biomass residues as (co-)fired in the project activity and, at the end of the lifetime of the existing plant, replacement of that plant by a similar new plant

Of the outlined baselines P5 and P6 may be ruled out as the new power plant is not a replacement for existing power generating units and is an addition to the capacity of power plants generating electricity from bagasse. P3 may be ruled out as setting up a similar sized fossil fuel power plant to supply to the grid is not feasible given the scale of the plant nor is it part of the core business of the company. P1 is not a credible baseline scenario as without the registration of the project as a CDM it would not occur, as demonstrated in section B5. P2 is not a credible baseline as this represents the current set-up at the plant and there is no requirement to generate more electricity for the sugar plant. P4 is a credible baseline – the generation of power in existing and/or new grid connected plants – as the power from the project activity will be fed into the grid and is thus expected to displace power from existing and planned capacity additions of the grid.

Heat baselines
H1 The proposed project activity not undertaken as a CDM 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. and efficiency that is common practice in the relevant industry sector)
H3 The generation of heat in an existing cogeneration plant, on-site or nearby the project site, using only fossil fuels
H4 The generation of heat in boilers using the same type of biomass residues
H5 The continuation of heat generation in an existing power plant, fired with the same type of biomass residues as in the project activity, and implementation of the project activity, not undertaken as a CDM project activity, at the end of the lifetime of the existing plant
H6 The generation of heat in boilers using fossil fuels
H7 The use of heat from external sources, such as district heat
H8 Other heat generation technologies (e.g. heat pumps or solar energy)

As the project is located next to a sugar factory we can rule out H3, H6, H7 and H8. H1 is not a credible baseline scenario as without the registration of the project as a CDM it would not occur, as demonstrated in section B3. H2 is not a credible baseline as the current generation of heat is sufficient to meet the demands of the sugar plant and therefore there is no requirement to install a lower heat efficiency plant. We therefore determine the heat baseline as H4 – the generation of heat in boilers using the same type of biomass residues, which conforms to the current set-up at the plant.

Biomass baselines

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.

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.
B3 The biomass residues are burnt in an uncontrolled manner without utilising it for energy purposes.
B4 The biomass residues are used for heat and/or electricity generation at the project site.
B5 The biomass residues are used for power generation, including cogeneration, in other existing or new grid connected power plants.
B6 The biomass residues are used for heat generation in other existing or new boilers at other sites.
B7 The biomass residues are used for other energy purposes, such as the generation of biofuels.
B8 The biomass residues are used for non-energy purposes, e.g. as fertilizer or as feedstock in processes.

From the alternatives listed above we can rule out B1, B2, B3, B5, B6, B7 and B8 as the biomass in the baseline scenario would be used by the sugar factory to generate power and heat. Therefore we are limited to B4, that the biomass would be used for heat and/or electricity generation at the project site.

From the analysis above the scenario that results from P4, H4 and B4 is scenario 12 – "The project activity involves the installation of a new biomass residue fired cogeneration unit, which is operated next to (an) existing biomass residue fired power generation unit(s). The existing unit(s) are only fired with biomass residues and continue to operate after the installation of the new power unit. The power generated by the new power unit is fed into the grid or would in the absence of the project activity be purchased from the grid. The biomass residues would in the absence of the project be used for heat generation in boilers at the project site. This may apply, for example, where the biomass residues have been used for heat generation in boilers at the project site prior to project implementation"

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality): >>

That the project is not part of the baseline is demonstrated using the latest tool for the demonstration and assessment of additionality, version 03, agreed at EB29.

Step 1. Identification of alternatives to the project activity consistent with current laws and Regulations

Realistic and credible alternatives to the project activity are defined through the following steps:

Sub-step 1a. Define alternatives to the project activity:

1. Identify realistic and credible alternative(s) available to the project participants or similar project developers that provide outputs or services comparable with the proposed CDM project activity. These alternatives are to include:
   - The proposed project activity undertaken without being registered as a CDM project activity;
   - Other realistic and credible alternative scenario(s) to the proposed CDM project activity scenario that deliver outputs and on services (e.g. electricity, heat or cement)

with comparable quality, properties and application areas, taking into account, where relevant, examples of scenarios identified in the underlying methodology;
• If applicable, continuation of the current situation (no project activity or other alternatives undertaken).

The proposed project activity not undertaken as a CDM is straightforward. The continuation of the current situation is also a credible alternative as the existing power plant satisfied (and would continue to satisfy) the demand of the sugar plant in terms of steam and electricity and the project activity only installs a turbine generator (no additional boilers will be installed for the supply of steam to the adjacent sugar factory). Other options that could supply comparable outputs to the project activity are restricted to investments in steam and electricity generation capacity. With the exception of the project activity, these are likely to be fossil fuel based systems and Bajaj Hindusthan Ltd is primarily a sugar company not a power company so such investments are not therefore considered plausible.

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

The above alternatives are all in compliance with applicable legal and regulatory requirements. Moreover, there is no foreseeable regulatory change that would make the above alternatives non-compliant.

Step 2. Investment Analysis.

Sub-step 2a. Determine appropriate analysis method

The propose project activity has dual revenues stream namely revenues from the sale of power to the grid and revenues from the sales of CERs and therefore option III benchmark analysis has been chosen.

Sub-step 2b – Option III. Apply benchmark analysis

The most suitable financial indicator chosen is the project IRR. The benchmark identified is WACC (weighted average cost of capital) and has been taken as 20.3%.

Independent financial advice confirms that investors in companies such as BHL expect that investments are only undertaken where the IRR exceeds the WACC.

The WACC has been calculated through the use of the Capital Asset Pricing Model (CAPM) using returns from the Sensex (Indian stock market), government bonds and the correlation of the BHL stock with that of the Sensex (β). The CAPM model derives the return on equity by:

$$ROE = r_{rf} + \beta\left(r_m - r_{rf}\right)$$

Where:

ROE is the return on equity
r_{rf} is the risk free interest rate
β is the volatility of the individual stock relative to the market
r_m is the market return

The risk free interest rates is determined from 10 year government bonds, β is taken from Bloomberg (a leading provider of stock market data) and r_m is taken from the market returns of the Sensex over the last

3 years. The data underlying this calculation is clearly shown in the attached spreadsheet and maybe verified from www.bseindia.com and the Reserve Bank of India (http://www.rbi.org.in/home.aspx#), the data on beta has been taken from Bloomberg and a copy of the price screen has been provided to the DOE.

Sub-step 2c. Calculation and comparison of financial indicators

The calculation of the project IRR is based on the revenues associated with the project – the sale of electricity and the sale of CERs. The costs associated with the project relate to administrative costs (the salaries of additional people employed), operation and maintenance of the plant and the maintenance costs of line. All these costs are in line with industry standards. These are evident in the data supplied to the DOE and all the supporting documents have been provided.

As per the initial analysis by BHL[4] on the viability of projects which undertake export to the grid it was made clear that the risks involved in undertaking such activities outweighed the benefits.

The terms in the power purchase agreement (PPA) do not define any tariff after the fourth year. The following tables show the PPA tariff as used in the IRR analysis and the resulting cash flows. This assumes that the fourth year tariff is carried forward unchanged for years 5 to 10. The evidence for the tariff has been provided to the DOE.

Tariff from the PPA as signed with UPPCL

Year 1	Rs/kWh	2.8600
Year 2	Rs/kWh	2.8900
Year 3	Rs/kWh	2.9300
Year 4	Rs/kWh	2.9700
Year 5	Rs/kWh	3.0200
Year 6	Rs/kWh	3.0200
Year 7	Rs/kWh	3.0200
Year 8	Rs/kWh	3.0200
Year 9	Rs/kWh	3.0200
Year 10	Rs/kWh	3.0200

The above table yields the following cash flows for the project activity:

			2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
			1	2	3	4	5	6	7	8	9	10
Electricity	MWh		20,736	28,823	28,823	28,823	28,823	28,823	28,823	28,823	28,823	28,823
Deduction for billable		2%	415	576	576	576	576	576	576	576	576	576
Tripping		10%	2,074	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
Actual export	MWh		18,248	25,364	25,364	25,364	25,364	25,364	25,364	25,364	25,364	25,364
Revenue, Rs 1000												
Electricity			52,188	73,303	74,317	75,332	76,600	76,600	76,600	76,600	76,600	76,600
Costs, Rs 1000												
O&M			11,002	11,442	11,900	12,376	12,871	13,386	13,921	14,478	15,057	15,659
Admin			4,000	4,160	4,326	4,499	4,679	4,867	5,061	5,264	5,474	5,693

[4] BHL presentation to investors, January 2005 , Page 73-76 provided to the DOE at the time of validation, http://www.bajajhindusthan.com/new.htm

UPEB maintenance		3,076	3,199	3,327	3,460	3,599	3,743	3,893	4,048	4,210	4,379
PBIDT											
Project flows	-220,039	34,110	54,501	54,764	54,996	55,451	54,605	53,725	52,810	51,859	50,869
Project IRR	**18.79%**										

		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
		1	2	3	4	5	6	7	8	9	10
PBIDT		34,110	54,501	54,764	54,996	55,451	54,605	53,725	52,810	51,859	50,869
CER revenues		9,812	13,639	13,639	13,639	13,639	13,639	13,639	13,639	13,639	13,639
PBIDT with CERs		43,922	68,140	68,403	68,635	69,090	68,244	67,364	66,449	65,498	64,508
Project flows	-220,039	43,922	68,140	68,403	68,635	69,090	68,244	67,364	66,449	65,498	64,508
Project IRR	**25.48%**										

It is clear from the above data that the project activity does not yield sufficient revenues without the consideration of the CDM and the chosen financial indicator is below the benchmark and is therefore additional.

Sub-step 2d. Sensitivity analysis

The financial attractiveness of the project depends largely on the PPA tariff for the sale of electricity. Therefore in the following analysis we have varied this critical parameter to demonstrate the robustness of the analysis.

We have assumed an increase of 1.5%[5] annually from year 5 onwards, when the tariff is not defined:

Tariff from the PPA as signed with UPPCL (with escalation):

Year 1	Rs/kWh	2.8600
Year 2	Rs/kWh	2.8900
Year 3	Rs/kWh	2.9300
Year 4	Rs/kWh	2.9700
Year 5	Rs/kWh	3.0200
Year 6	Rs/kWh	3.0614
Year 7	Rs/kWh	3.1033
Year 8	Rs/kWh	3.1459
Year 9	Rs/kWh	3.1890
Year 10	Rs/kWh	3.2327

The cash flows associated with the project activity under this assumption of a decreasing tariff are shown in the table below:

		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
		1	2	3	4	5	6	7	8	9	10
Electricity	MWh	20,736	28,823	28,823	28,823	28,823	28,823	28,823	28,823	28,823	28,823
Deduction for billable	2%	415	576	576	576	576	576	576	576	576	576
Tripping	10%	2,074	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
Actual export	MWh	18,248	25,364	25,364	25,364	25,364	25,364	25,364	25,364	25,364	25,364

Revenue, Rs 1000

[5] This is based on the average escalation given in the first four years in the PPA.

Electricity		52,188	73,303	74,317	75,332	76,600	77,650	78,714	79,793	80,886	81,995
Costs, Rs 1000											
O&M		11,002	11,442	11,900	12,376	12,871	13,386	13,921	14,478	15,057	15,659
Admin		4,000	4,160	4,326	4,499	4,679	4,867	5,061	5,264	5,474	5,693
UPEB maintenance		3,076	3,199	3,327	3,460	3,599	3,743	3,893	4,048	4,210	4,379
PBIDT											
Project flows	-220,039	34,110	54,501	54,764	54,996	55,451	55,655	55,839	56,003	56,145	56,264
Project IRR	**19.24%**										
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
		1	2	3	4	5	6	7	8	9	10
PBIDT		34,110	54,501	54,764	54,996	55,451	55,655	55,839	56,003	56,145	56,264
CER revenues		9,812	13,639	13,639	13,639	13,639	13,639	13,639	13,639	13,639	13,639
PBIDT with CERs		43,922	68,140	68,403	68,635	69,090	69,294	69,478	69,642	69,784	69,903
Project flows	-220,039	43,922	68,140	68,403	68,635	69,090	69,294	69,478	69,642	69,784	69,903
Project IRR	**25.80%**										

It is clear from the above analysis that the project IRR is still below the chosen benchmark and therefore demonstrates the robustness of the investment analysis in the even of variation in the tariff.

It is further shown below how any decrease in the tariff may affect the returns associated with the project activity. We have assumed a decrease of 1.5% annually from year 5 onwards, when the tariff is not defined:

Year 1	Rs/kWh	2.8600
Year 2	Rs/kWh	2.8900
Year 3	Rs/kWh	2.9300
Year 4	Rs/kWh	2.9700
Year 5	Rs/kWh	2.9255
Year 6	Rs/kWh	2.8816
Year 7	Rs/kWh	2.8383
Year 8	Rs/kWh	2.7958
Year 9	Rs/kWh	2.7538
Year 10	Rs/kWh	2.7125

The cash flows associated with the project activity under this assumption of a decreasing tariff are shown in the table below:

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
		1	2	3	4	5	6	7	8	9	10
Electricity	MWh	20,736	28,823	28,823	28,823	28,823	28,823	28,823	28,823	28,823	28,823
Deduction for billable	2%	415	576	576	576	576	576	576	576	576	576
Tripping	10%	2,074	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
Actual export	MWh	18,248	25,364	25,364	25,364	25,364	25,364	25,364	25,364	25,364	25,364
Revenue, Rs 1000											
Electricity		52,188	73,303	74,317	75,332	74,202	73,089	71,992	70,913	69,849	68,801
Costs, Rs 1000											
O&M		11,002	11,442	11,900	12,376	12,871	13,386	13,921	14,478	15,057	15,659

Admin		4,000	4,160	4,326	4,499	4,679	4,867	5,061	5,264	5,474	5,693
UPEB maintenance		3,076	3,199	3,327	3,460	3,599	3,743	3,893	4,048	4,210	4,379
PBIDT											
Project flows	-220,039	34,110	54,501	54,764	54,996	53,053	51,094	49,118	47,123	45,108	43,070
Project IRR	**17.77%**										
		2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
		1	2	3	4	5	6	7	8	9	10
PBIDT		34,110	54,501	54,764	54,996	53,053	51,094	49,118	47,123	45,108	43,070
CER revenues		9,812	13,639	13,639	13,639	13,639	13,639	13,639	13,639	13,639	13,639
PBIDT with CERs		43,922	68,140	68,403	68,635	66,692	64,733	62,757	60,762	58,747	56,709
Project flows	-220,039	43,922	68,140	68,403	68,635	66,692	64,733	62,757	60,762	58,747	56,709
Project IRR	**24.71%**										

Step 3 Barrier analysis

Sub-step 3a

The institutional framework (specifically the electricity off-take agreement) has traditionally been the factor that has stopped the development of such projects in Uttar Pradesh – before 2004 no similar projects were implemented in Uttar Pradesh. Although the Electricity Act, 2003 brought some liberalisation to the electricity sector, its full implementation has been delayed and some of the more free market elements envisaged in the legislation have not been implemented or are not applicable to the project (the project activity will not wheel or bank power). In essence the risks prior to the passing into law of the Electricity Act, 2003 remain. A feature of the market that has changed is a more functioning state electricity regulatory commission but this was introduced in Uttar Pradesh in 2000 through the Electricity Regulatory Commissions Act, 1998. The main feature of the market that has changed since 2004 is the introduction of a carbon market and similar projects in the state have been proposed as CDMs as demonstrated in the common practise section.

Under the terms of the power purchase agreement (PPA) granted to the project activity there remains uncertainty in the tariff, the tariff may be reviewed post 2009 as there is no specified rate beyond the 2009-10 season. This provides considerable uncertainty to the project developer as to future rates in force. The actual tariff in the first year for the project activity will be Rs 2.86/kWh which is far below the earlier Ministry of Non-Conventional Energy Sources (MNES). The MNES advised a tariff of Rs 2.25 in 1994-95 escalated at a rate of 5%, which currently equates to a tariff of Rs 3.60/kWh. The current tariff has been issued as a Tariff Order by the Uttar Pradesh Electricity Regulatory Commission and the discussions surrounding its issuance indicate the significant differences between the promoters of such projects and UPPCL[6]. The lower tariff in Uttar Pradesh is confirmed by those prevalent in other states, in Maharashtra[7] and Tamil Nadu[8] the tariff is Rs.3.24/kWh and Rs.3.15/kWh respectively. Therefore, the registration of the project as a CDM will "increase" the tariff and therefore provides a significant additional revenue stream that brings it up to more realistic levels considering the risks in the

---

[6] http://www.uperc.org/

[7] Maharashtra Electricity Regulatory Commission, Page 2, http://mercindia.org.in/pdf/Biomass%20Order-8.8.05.zip

[8] Tamil Nadu Electricity Regulatory Commission, Page 29, http://tnerc.tn.nic.in/orders/nces%20order%20-approved%20order%20host%20copy.pdf

project and the uncertainty going forward. As mentioned in the sensitivity analysis section, the real possibility that the tariff post 2011 is reduced exists. CER revenue acts as a financial buffer that can mitigate this financial risk.

Aside from the regulatory framework there is significant counterparty risk for the project developers – the problems associated with selling to the state electricity boards cannot be underestimated and this has been a major impediment to investment in the power sector by private companies. The actual counterparty to the project will not be UPPCL but a local distribution company which has been established by UPPCL. This new entity currently has no balance sheet and there are no guarantees offered from UPPCL on its behalf. Given the experience in other states where the counterparty has been the state electricity board this presents a significant risk for the project.

Probably the most significant barrier to the project activity is the availability of bagasse which is obtained from the crushing of sugarcane which is a seasonal crop. The project activity takes place next to a sugar factory and the power plant is dependent on the sugar factory for its supply of steam which in turn is generated from the bagasse. In Uttar Pradesh there is a large concentration of sugar factories and therefore it could be argued that this risk is minimised by the supply of bagasse from other plants. However given the variability in cane crops and the diversion of cane to gur and khandsari the bagasse prices have been rising to a level where it is uneconomic to purchase for power generation[9]. Reduced bagasse availability is a project specific risk. Reduced bagasse supply means less cane crushed and hence less electricity and steam required by the plant. Thus this risk does not apply to the baseline scenario.

The project could try to collect surplus bagasse from the surrounding region but this will require investment in collection systems and is not seen as a viable fuel sourcing strategy. Any reduction in the supply of cane will therefore reduce the plant load factor of the power plant and therefore in order to minimise this risk the additional CER revenue stream will be of importance. At current prices the carbon credit revenue stream will provide about Rs 0.47/kWh of additional revenues.

A feature of the project activity that requires extra training and investment in personnel is the level of grid instability. This is likely to impact the exportable power from the project activity and the expectation is that there is likely to be 5% downtime due to tripping of the grid.

Sub-step 3b

In summary it can be seen that there are significant barriers to the development of project activity. The identified barriers affect all similar types of plants and therefore the policy of similar plants has been to adopt cogeneration for their own captive consumption which is one of the alternatives to the project activity and therefore barriers presented above do not prevent the continuation of the current situation.

Step 4. Common practice analysis

Sub-step 4a

---

[9] During the last season, 2004/05, bagasse prices rose to over Rs 1,000/tonne ex factory.

In the state of Uttar Pradesh there are 111 sugar factories, 16 of which export electricity to the grid[10]. However of the 16 units 12 have capacities of less than 15MW, the smallest being1.8 MW at Monnet and the largest of 12 MW. Of the four plants of a similar scale, three are part of the Balrampur Chini group that has been active in pursuing CDM status for their projects and the fourth is part of Triveni which has also proposed the project as a CDM. It can therefore be concluded that the project under consideration is not common practice in Uttar Pradesh[11].

More generally the project should not be considered as common practise in India. In India the latest data available on bagasse cogeneration from The Sugar Technologists' Association of India lists 24 mills with bagasse cogeneration capacities greater than 15MW. Considering that there are 517 sugar mills in India the uptake of cogeneration on a similar scale, over 15MW, represents only 4.6% penetration of the potential in terms of the number of sugar mills employing such systems[12].

Sub-step 4b

As demonstrated earlier there is no evidence of any similar project being undertaken without the benefit of CDM.

The above analysis demonstrates that the proposed project activity is not a common practice and all the similar projects are being proposed as CDM and therefore is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

>>
The application of the baseline methodology results in scenario 12 of ACM0006, as outlined in B4. This requires the calculation of baseline emission associated with the electricity generation, the generation of heat and the usage of biomass. Broadly the emission reductions from the project are calculated from the application of the following equation:

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

where:

ER_y	Emission reductions of the project activity during the year y (tCO_2/yr)
$ER_{electricity,\,y}$	Emissions reductions due to displacement of electricity during the year y (tCO_2/yr)
$ER_{heat,\,y}$	Emission reductions due to displacement of heat during the year y (tCO_2/yr)
$BE_{biomass,\,y}$	Baseline emissions due to natural decay or burning of anthropogenic source of biomass residues during the year y (tCO_2/yr)
PE_y	Project emissions during the year y (tCO_2/yr)

[10] "List of Cane Sugar Factories and Distilleries, Season 2004-05", Published by The Sugar Technologists' Association of India, New Delhi.

[11] One Dhampur plant that was bought by Balrampur Chini Mills recently has a 30MW turbine generator, however this was iSnstalled in an existing plant and was also purchased second hand from a coal fired plant and converted to operate on bagasse.

[12] "List of Cane Sugar Factories and Distilleries, Season 2004-05", Published by The Sugar Technologists' Association of India, New Delhi. It should be further highlighted that five states account for this entire capacity and that five of the six plants in Tamil Nadu operate on fossil fuels.

L_y Leakage emissions during the year y (tCO_2/yr)

The methodology requires us to demonstrate for scenario 12 that the lifetime of the baseline is consistent with the period that emission reductions are being claimed for. In the case of the project activity the existing power plant has a technical lifetime in excess of 10 years.

In terms of emission reductions due to heat generation we do not claim for these in the case of the project activity but are required to show that emissions do not arise from the combustion of more biomass. In line with the methodology this may be shown by demonstrating that the efficiency of heat generation in the project is larger than the baseline scenario and assume $ER_{heat,y} = 0$, i.e.:

$$\varepsilon_{th,projectplant} > \varepsilon_{th,referenceplant}$$

In order to show this we have calculated the heat generated per unit of biomass in the project activity and shown that this is greater than or equal to the heat generated per unit of biomass in the baseline. This may be demonstrated on the basis of the specification of the boilers (operating temperatures and pressures) and the enthalpies that arise (we have considered the same efficiencies of the two boilers).

Consideration of heat emissions

Existing configuration (21kg/cm², 310°C)			New configuration (45kg/cm², 450°C)		
Capacity	kg/hr	1	Capacity	kg/hr	1
Enthalpy out	kCal	727	Enthalpy out	kCal	793
Enthalpy in	kCal	110	Enthalpy in	kCal	180
NCV	kCal/kg	1,813	NCV	kCal/kg	1,813
Efficiency	%	70%	Efficiency	%	75%
Bagasse	kg/hr	0.4862	Bagasse	kg/hr	0.4508
Steam/bagasse		2.06	Steam/bagasse		2.22

The above table therefore highlights that the project has a higher thermal efficiency than the baseline and therefore that $ER_{heat,\ y} = 0$.

In terms of baseline emission arising from the natural decay or uncontrolled burning of biomass we do not claim for these under scenario 12 as the biomass would be combusted in the baseline scenario, therefore as set out in the methodology for scenario 12 $BE_{biomass,\ y} = 0$.

The project emissions arising from the project activity are limited to four sources; combustion of fossil fuels for the transport of biomass to the site, on-site consumption of fossil fuels, emissions due to the electricity consumption at the site and methane emissions from the combustion of biomass. As the biomass will be produced in the adjacent sugar factory there will be no emissions arising from the transportation of biomass. The project activity does not plan to co-fire any fossil fuels in the boiler and therefore emissions from these sources are not included. We do not seek to claim baseline emissions from the decay of biomass we are not required to account for the methane emissions from the combustion of biomass. Lastly, in terms of electricity consumption arising as a result of the project activity this is not included as the only consumption will be from the auxiliaries which already accounted for in the baseline calculation.

Therefore $PE_y = 0$.

In line with the methodology leakage is not considered for scenario 12 and therefore $L_y = 0$.

$ER_{heat,y}$, , $BE_{biomass,y}$, , PE_y and L_y have not be considered in the equation as it has been shown that these are equal to zero or are not required to be considered under the application of the methodology.

The emission reduction equation therefore reduces to:

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

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

where:

EG_y	is the net quantity of increased electricity generation as a result of the project activity during the year y in MWh/yr
$EF_{electricity,,y}$	is the CO_2 emission factor for the electricity displaced due to project activity during the year in tons CO_2/MWh

And in line with scenario 12 EG_y is determined from

$$EG_y = MIN\left[\left(EG_{projectplant,y}\right) and \left(EG_{total,y} - \frac{EG_{historic,3yr}}{3}\right)\right]$$

Where:

EG_y	is the net quantity of increased electricity generation as a result of the project activity (incremental to the baseline generation) during the year y in MWh/yr
$EG_{projectplant,\ y}$	is the net quantity of electricity generated in the project plant during the year y in MWh/yr
$EG_{total,\ y}$	is the net quantity of electricity generated in all power units at the project site, generated from firing the same types(s) of biomass as in the project plant, including the new power unit installed as part of the project activity and any previously existing units, during the year y in MWh/yr
$EG_{historic,\ 3yr}$	is the net quantity of electricity generated during the most recent three years in all power plants at the project site, generated from firing the same types(s) of biomass as used in the project plant, in MWh

The calculation of EF_y is carried out through the application of the relevant sections of methodology ACM0002 version 6. The combined margin, representing EF_y is explicitly presented in Annex 3.

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

(Copy this table for each data and parameter)

Data / Parameter:	$F_{i,j,y}$
Data unit:	Mt, mcbm, kl
Description:	Consumption of fossil fuel by existing grid connected power plants

Source of data used:	Central Electricity Authority
Value applied:	Varies for each plant
Justification of the choice of data or description of measurement methods and procedures actually applied :	For thermal power plants the CEA provides coal consumption data for each grid based unit, whilst for gas based plants aggregate fuel consumption data is available. The choice of data therefore satisfies the guidance in the methodology, ACM0002.
Any comment:	Full data set provided in Annex 3

Data / Parameter:	**$GEN_{j,y}$**
Data unit:	GWh
Description:	Generation of electricity by existing grid connected power plants
Source of data used:	Central Electricity Authority
Value applied:	Varies for each plant
Justification of the choice of data or description of measurement methods and procedures actually applied :	The CEA provides data on the generation of electricity by grid based units.
Any comment:	Full data set provided in Annex 3

Data / Parameter:	**NCV_i**
Data unit:	TJ/kt
Description:	Net calorific value of the fuel combusted in grid based power plants used in the determination of the emission factor
Source of data used:	Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual Table 1-2 and India's National Communication, chapter 2, page 37 for coal.
Value applied:	Varies for each fuel type
Justification of the choice of data or description of measurement methods and procedures actually applied :	National net calorific values are not available and therefore we have used country specific IPCC data.
Any comment:	Full data set provided in Annex 3

Data / Parameter:	**$EF_{CO2,i}$**
Data unit:	tCO2/TJ
Description:	Tonnes of carbon dioxide per energy unit of fuel in grid based plants used in the determination of the emission factor
Source of data used:	Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual Table 1-1 and India's National Communication, chapter 2, page 37 for coal.
Value applied:	Varies for each fuel type
Justification of the	The values in Table 1-1 have been converted to a carbon dioxide equivalent by

choice of data or description of measurement methods and procedures actually applied :	multiplying by 44/12.
Any comment:	Full data set provided in Annex 3

Data / Parameter:	**$OXID_i$**
Data unit:	%
Description:	Oxidation factor applied to the combustion of fuels in grid based plants for the determination of the emission factor
Source of data used:	Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual Table 1-6
Value applied:	98% for coal and 99.5% for gas
Justification of the choice of data or description of measurement methods and procedures actually applied :	
Any comment:	

Data / Parameter:	**$EG_{historic}$**
Data unit:	MWh
Description:	Three year average net electricity generation
Source of data used:	Plant records
Value applied:	38,118
Justification of the choice of data or description of measurement methods and procedures actually applied :	The data has been taken from recorded data at the plant for the last three years.
Any comment:	

B.6.3 Ex-ante calculation of emission reductions:

>>

In order to calculate the baseline emissions we apply the following equations.

$$EG_y = MIN\left[\left(EG_{projectplant,y}\right) and \left(EG_{total,y} - \frac{EG_{historic,3yr}}{3}\right)\right]$$

The emission reductions due to electricity generation are the product of EG_y determined above and the grid based emission factor, EF_y, as set out in ACM0002.

In the case of project activity $EG_y = EG_{project\ plant,\ y}$ as this results in a lower value.

$EG_{project\ plant,\ y}$ = 28,823MWh/yr

Therefore, EG_y = 28,823MWh/yr

$$ER_{electricity} = EG_y . EF_y$$

Where:

$ER_{eletricity,\ y}$	the emission reductions relating to the electricity generation from the project activity tCO_2e
EG_y	the net quantity of increased electricity generation as a result of the project activity (incremental to baseline generation) during the year y in MWh/yr
EF_y	the grid based emission factor, determined through the combined margin approach as set out in ACM0002 tCO_2e/MWh

EF_y has been set at 0.910 tCO_2e/MWh as shown in Annex 3 and combining this with EG_y (28,823MWh/yr) gives $ER_{electricity,\ y}$ = 26,229 tCO_2e. Emission reductions here are calculated assuming the plant stabilises after the first year. For the first year, $ER_{electricity,\ y}$ = 18,870 tCO_2e assuming 100 days of operation.

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

>>

	Estimation of project activity emissions (tonnes of CO_2e)	Estimation of baseline emissions (tonnes of CO_2e)	Estimation of leakage (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
Year 1	0	18,870	0	18,870
Year 2	0	26,229	0	26,229
Year 3	0	26,229	0	26,229
Year 4	0	26,229	0	26,229
Year 5	0	26,229	0	26,229
Year 6	0	26,229	0	26,229
Year 7	0	26,229	0	26,229
Year 8	0	26,229	0	26,229
Year 9	0	26,229	0	26,229
Year 10	0	26,229	0	26,229
Total tonnes of CO_2e	0	**254,930**	0	**254,930**

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

B.7.1 Data and parameters monitored:

(Copy this table for each data and parameter)

Data / Parameter:	**$EG_{Projectplant,\ y}$**
Data unit:	MWh/yr
Description:	Electrical energy generated by the project activity
Source of data to be	On site measurements

used:	
Value of data applied for the purpose of calculating expected emission reductions in section B.5	28,823
Description of measurement methods and procedures to be applied:	The project activity will install a DCS system which will permit continuous monitoring and measurement. Hourly recordings of data will be taken from energy meters located at the project activity site. This data will be recorded hourly by the Switch Board attendant and entered into logbooks on site. This hourly data will be signed off at the end of every shift by an engineer in charge of the shift and again at the end of each day and signed off by the power plant manager. The meters will be calibrated annually by an independent third party.
QA/QC procedures to be applied:	The net electricity generation will be crosschecked with sales receipts of electricity and the annual energy balance
Any comment:	

Data / Parameter:	**$EG_{total, y}$**
Data unit:	MWh/yr
Description:	Net quantity of electricity generated in all power units at the project site, generated from firing the same type(s) of biomass residues as in the project plant, including the new power unit installed as part of the project activity and any previously existing units, during the year *y*
Source of data to be used:	On site measurements
Value of data applied for the purpose of calculating expected emission reductions in section B.5	72,778
Description of measurement methods and procedures to be applied:	For the existing power plant hourly recordings of data will be taken from energy meters located at the site. This data will be recorded hourly by the Switch Board attendant and entered into logbooks on site. This hourly data will be signed off at the end of every shift by an engineer in charge of the shift and again at the end of each day and signed off by the power plant manager. The meters will be calibrated annually by an independent third party.
QA/QC procedures to be applied:	The net electricity generation will be crosschecked with sales receipts of electricity and the annual energy balance
Any comment:	

B.7.2 Description of the monitoring plan:

>>
The monitoring of electricity data revolves around the electricity generation from the turbine generators and the auxiliary consumption of the power plant. All auxiliary units at the power plant will be monitored and the meters will be checked and calibrated each year to ensure the quality of the data. There will also be main meters attached to each turbine generator to determine their total generation which again will be calibrated each year.

The monitoring frequency will be done on a continuous basis through a DCS system (for the new power plant) but records will be maintained on an hourly basis for all turbine generators by the turbine operators in logbooks. The Additional Manager, Electrical will then collate these data at the end of each day. The daily reports are sent to the laboratory which then produces a Daily Manufacturing Report, which is distributed within the plant and to the head office.

The recording of data will be carried out by switchboard operators who will report this to the shift engineer, the shift engineers will report to the power plant manager. The daily electricity generation will be part of the overall management information systems of the.

There will be logbooks held to record the data and this will also be stored electronically for a minimum of two years after the end of the crediting period. The DCS system has the capability to record all the data and will be used as a back up and also a cross check for the meter readings.

All the meters will be checked and calibrated each year by an independent agency to ensure the quality of the data.

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

>>
10/08/2006
Robert Taylor, Agrinergy Ltd, project participant, contact details as listed in Annex I.
Dr. A. V. Singh, BHL, project participant, contact details as listed in Annex I.

SECTION C. Duration of the project activity / crediting period

C.1.1. Starting date of the project activity:

>>
15/01/2006, representing the date on which civil work began.

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

>>
20 years 0 months

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

A fixed ten year crediting period has been chosen.

C.2.1. Renewable crediting period

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

>>
Not applicable

C.2.1.2. Length of the first crediting period:

>>
Not applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>
15/03/2007 or the date of registration whichever is later.

C.2.2.2. Length:

>>
10 years

SECTION D. Environmental impacts

>>

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

>>
In relation to the baseline scenario no negative environmental impacts will arise as a result of the project activity. The establishment of the power plant does not require an EIA.

The positive environmental impacts arising from the project activity are:

- A reduction in carbon dioxide emissions from the replacement of fossil fuels which would be generated under the baseline scenario
- A reduction in the emissions of other harmful gases (NOx and SOx) that arise from the combustion of coal in power generation
- A reduction in ash in comparison to the baseline scenario due to the lower ash content of bagasse relative to coal (5% versus 45% respectively).

The power plant currently meets all environmental legislations as set out by the State Pollution Control Board and there will be on-going monitoring of the plant by this state body. A “No objection certificate” has been obtained from the Uttar Pradesh Pollution Control Board for the project activity. A “Consent to operate” will be provided annually and this will form part of the monitoring procedures.

The plant will install a wet scrubber and a ESP at the exit of the boiler to limit suspended particulate matter in the flue gases to less than 150 mg/Nm^3. The waste water from the power plant will be treated and once treated will meet the norms as stipulated by the Pollution Control Board.

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

>>
Environmental impacts are not considered significant.

SECTION E. Stakeholders' comments

>>

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

>>

The stakeholder review has been conducted on three levels:

- A local stakeholder review
- A national stakeholder review which will be undertaken through the approval by the Ministry of Environment and Forests (the Indian DNA) and consent to operate from the Uttar Pradesh Pollution Control Board.
- An international stakeholder review which will be conducted at the time of validation.

The institutions are already in place for the national and international stakeholder review and any comments arising from these processes will be incorporated prior to registration.

A notice has been placed in local newspapers in both Hindi and English providing information on the project and inviting comments. A formal stakeholder consultation meeting has been undertaken with representatives of the local community and the State Pollution Control Board on 10th August 2006.

Other stakeholders that have been notified of the project, through consents and approvals required for the investment, are the Uttar Pradesh Power Corporation Limited through the issuance of a PPA and the State Boiler and State Electrical Inspectorate which have visited the site to approve the plans and construction.

Pollution Control Board has issued its consents for air and water pollution with some conditions.

E.2. Summary of the comments received:

>>

The main issues raised during the stakeholder consultation meeting at the project site were about the supply of electricity in the region and benefits to the farmers due to the establishment of the co-generation plant. These are answered in section E.3.

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

>>

The distribution of electricity lies completely with UPPCL policies. But since the proposed project activity exports to the grid and it will add to the current capacity of UPPCL, it will benefit the state in general and the region in particular. The benefits to the farmers would be in terms of employment at the project site as well as expected better returns. This has been described in detail in section A.2. The consents from pollution control board are obtained annually and the conditions specified in the consents will be followed strictly under the supervision of Dr. A V Singh (Vice President, EHS-BHL).

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Bajaj Hindusthan Ltd
Street/P.O.Box:	Nariman Point
Building:	Bajaj Bhawan
City:	Mumbai
State/Region:	
Postfix/ZIP:	400 021
Country:	India
Telephone:	+91 (0) 22 2202 3626
FAX:	+91 (0) 22 2202 2238
E-Mail:	
URL:	www.bajajhindusthan.com
Represented by:	
Title:	Dr
Salutation:	
Last Name:	Singh
Middle Name:	V
First Name:	A
Department:	Environment
Mobile:	09873561813
Direct FAX:	+91 (0) 120 254 3949
Direct tel:	+91 (0) 120 254 3939
Personal E-Mail:	avsingh@bajajhindusthan.com

Organization:	Agrinergy Ltd
Street/P.O.Box:	
Building:	Suite 205, Eagle Tower
City:	Cheltenham
State/Region:	Montpellier Drive
Postfix/ZIP:	GL50 1TA
Country:	UK
Telephone:	+44 1425 206345
FAX:	+44 1425 206346
E-Mail:	
URL:	www.agrinergy.com
Represented by:	
Title:	Director
Salutation:	Mr
Last Name:	Atkinson
Middle Name:	
First Name:	Ben
Department:	
Mobile:	+44 7960 970974
Direct FAX:	+44 1425 206346
Direct tel:	+44 1425 206345
Personal E-Mail:	ben.atkinson@agrinergy.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The project has not received any public funding.

Annex 3

BASELINE INFORMATION

In line with the methodology to calculate the carbon dioxide emissions factor, we use the relevant sections of ACM0002 (Consolidated baseline methodology for grid-connected electricity generation from renewable sources). The combined margin presented below consists of the calculation of the average of the Operating Margin (OM) and the Build Margin (BM). In calculating the OM, we select the Simple OM option. Whilst Dispatch Data Analysis is the preferred method of calculating the OM, this is not selected because the required dispatch order data are not available in India.

The first step in selecting the Simple OM is to show that the proportion of low-cost/must run resources are less than 50% of total generation in the average of the last 5 years of data[13]. Low cost/must-run resources typically include hydro, geothermal, wind/ low cost biomass nuclear and solar generation. In addition, we must consider the possibility that coal is obviously used as must-run. In the Northern Region, the marginal costs of generation from coal are above those of renewable sources such as hydro, wind, nuclear and low-cost biomass. Moreover, coal plants have the possibility to "ramp-up" and "ramp-down". We therefore conclude that coal generation is not an obvious must-run resource. Low-cost/must run resources identified are therefore restricted to hydro and nuclear (the CEA does not provide any generation data from low-cost biomass and wind resources in the Northern Region). The following table clearly demonstrates the low percentage that low-cost/must run sources constitute of total generation and therefore confirms the choice of Simple OM.

Table 3: Units operating in the Northern Region

	2005-6 Generation, GWh	2004-5 Generation, GWh	2003-4 Generation, GWh	2002-3 Generation, GWh
Thermal	131,504	131,482	123,737	118,337
Nuclear	41,713	7,338	37,288	30,221
Hydro	6,444	36,105	7,364	8,642
Hydro/nuclear as % of total	**26.80%**	**24.84%**	**26.52%**	**24.72%**

Source: CEA Generation report,
http://www.cea.nic.in/god/opm/Monthly_Generation_Report/18col_05_03.pdf#sear

The calculation of the Simple OM initially requires us to calculate a CO_2 emission coefficient for thermal power plants based on the type of fuel used.

As per the methodology, the CO_2 emission coefficient $COEF_i$ is obtained from the following equation:

$$COEF_i = NCV_i . EF_{CO2,i} . OXID_i$$

Where:

NCV_i is the net calorific value (energy content) per mass unit of a fuel i,
$OXID_i$ is the oxidation factor of the fuel,

[13] We have used a 4 year average as data for 5 years generation is not available, see http://www.cea.nic.in/god/opm/Monthly_Generation_Report/index_Monthly_Generation_Report.html

$EF_{CO2,i}$ is the CO_2 emission factor per unit of energy of the fuel i.

In line with the methodology where available, local values of NCV_i and $EF_{CO2,i}$ should be used. If no such values are available, country-specific values should be used. The following table shows the NCV and EF factors used in the calculation of the Northern Region emission factor.

Table 4: Factors used in calculation of the CO_2 emission coefficient

	NCV_i,		$OXID_i$, %		$EF_{CO2,i}$, tC/TJ	
	Factor	**Source**	**Factor**	**Source**	**Factor**	**Source**
Coal	19.23 TJ/kt	India's Initial National Communication to the UNFCCC[2]	98	IPCC	26.13	India's Initial National Communication to the UNFCCC
Gas	37.68 TJ/cbm	Gail and IPCC[3]	99.5	IPCC	15.3	IPCC
HSD	43.33	IPCC	99	IPCC	20.2	IPCC
Naptha	45.01	IPCC	99	IPCC	20	IPCC

ACM0002 states "Plant emission factors used for the calculation of operating and build margin emission factors should be obtained in the following priority:

1. Acquired directly from the dispatch center or power producers, if available; or
2. Calculated, if data on fuel type, fuel emission factor, fuel input and power output can be obtained for each plant; if confidential data available from the relevant host Party authority are used the calculation carried out by the project participants shall be verified by the DOE and the CDM-PDD may only show the resultant carbon emission factor and the corresponding list of plants.
3. Calculated, as above, but using estimates such as: default IPCC values from the IPCC 1996 Revised Guidelines and the IPCC Good Practice Guidance for net calorific values and carbon emission factors for fuels instead of plant-specific values (note that the IPCC Good Practice Guidance includes some updates from the IPCC 1996 Revised Guidelines); technology provider's name plate power plant efficiency or the anticipated energy efficiency documented in official sources (instead of calculating it from fuel consumption and power output). This is likely to be a conservative estimate, because under actual operating conditions plants usually have lower efficiencies and higher emissions than name plate performance would imply; conservative estimates of power plant efficiencies, based on expert judgments on the basis of the plant's technology, size and commissioning date; or
4. Calculated, for the simple OM and the average OM, using aggregated generation and fuel consumption data, in cases where more disaggregated data is not available."

In India, the CEA is not a dispatch centre, and therefore Option 1 above cannot be calculated. Option 2 can be taken in so far as the CEA does provide coal consumption data for each plant. However the CEA does not provide coal NCV figures for each plant and therefore IPCC data has been used. The following equation is applied to the fuel consumption and generation to arrive at the Simple OM.

---

[2] http://natcomindia.org/pdfs/chapter2.pdf

[3] http://www.gailonline.com/customerzone/power.htm. NCV 90% of GCV.

$$EF_{OM,y} = \frac{\sum_{i,j} F_{i,j}.COEF_{i,j}}{\sum_{j} GEN_{j,y}}$$

In the case of gas stations, individual fuel consumption for each plant is not available. Aggregate consumption at the state and regional level is instead provided by the CEA. These data are only available for 2004-5 therefore we use these data to derive an average emission factor for gas stations in the Northern Region. The average emission factor is then applied to 2004-05 generation in the calculation of the CM[4].

The data on fuel consumption and generation for gas stations in the Northern Region is outlined below:

Table 5: Fuel Consumption and generation from gas stations in the Northern Region 2004-05

State	Natural gas consumption (mcbm)	HSD consumption (kl)	Naptha consumption (kl)	Total Generation (GWh)
Delhi	968	11	0	4,091
Jammu & Kashmir	0	5,209	0	24
Rajasthan	220	4,083	0	354
Central	2,870	265,744	243,961	15,522
Total				**19,991**

Source: CEA General Review 2006, Table 6.1, pp. 117

These data are combined with the above data on fuel specific gravities, calorific values, emission factors and oxidation factors to determine total emission from the above gas stations:

Table 6: Total emissions from gas stations in Northern Region, 2004-05

State	Emission from natural gas (tCO_2)	Emissions from HSD (tCO_2)	Emissions from Naptha (tCO_2)	Total Emissions (tCO_2)
Delhi	2,161,331	31	0	2,161,362
Jammu & Kashmir	0	14,564	0	14,564
Rajasthan	491,212	11,416	0	502,627
Central	6,408,079	743,007	621,814	7,772,900
Total	**9,060,621**	**769,018**	**621,814**	**10,451,453**

Dividing total emissions by total generation from gas stations gives an average emission factor for gas stations in the Northern Region of 0.5228 tCO_2/MWh for 2004-05.

Annual generation data for each power plant in the Northern Region is provided by the CEA[14]. (http://cea.nic.in/god/opm/Monthly_Generation_Report/18col_05_03.pdf).

---

[4] Steam stations use coal but gas may be also used as auxiliary fuel at these stations. The volume used is small and exclusion of this gas from fuel consumption calculation is conservative.

[14] http://cea.nic.in/god/opm/Monthly_Generation_Report/18col_05_03.pdf and

Coal consumption data for thermal power plants is also provided by the CEA report "Performance Review of Thermal Power Stations". (http://cea.nic.in/Th_per_rev/start.pdf). The CEA year runs from April to March.

Net imports from connected grid systems must also be considered. As outlined in ACM002, net imports from connected systems are only accounted for in the Operating Margin calculation. In terms of the applicable emissions factor, ACM002 states that:

"For the purpose of determining the Operating Margin (OM) emission factor, as described below, use one of the following options to determine the CO2 emission factor(s) for net electricity imports (*COEFi,j,imports*) from a connected electricity system within the same host country(ies):

(a) 0 tCO2/MWh, or
(b) the emission factor(s) of the specific power plant(s) from which electricity is imported, if and only if the specific plants are clearly known, or
(c) the average emission rate of the exporting grid, if and only if net imports do not exceed 20% of total generation in the project electricity system, or
(d) the emission factor of the exporting grid, determined as described in steps 1,2 and 3 below, if net imports exceed 20% of the total generation in the project electricity system."

Net imports from other regional grids account for less than 20% of total generation and therefore the average emission rate of the exporting grid may be selected. The determination of the carbon emissions factors for the exporting grids is based on an average grid emission rate as outlined in the methodology. The following tables outline the net import data and the emission factors for each grid:

Table 9: Net Imports from Other Regional Grids to the Northern Region (GWh)

	2004/05	2003/04	2002/03
From Southern	120	0	0
From Western	320	0	0
From Eastern	3043	117	827
From N Eastern	0	0	0

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

Table 10: Average emission rates for other Regional Grids (tCO2/MWh)

	2004/05	2003/04	2002/03
Northern CEF	0.83	0.81	0.84
Southern CEF	0.86	0.90	0.89
Western CEF	1.14	1.14	1.14
N Eastern CEF	0.36	0.41	0.40
Eastern CEF	1.22	1.23	1.17

Calculated using average emission factors of exporting grids

http://cea.nic.in/god/opm/Monthly_Generation_Report/18col_04_03.htm

Combining the above emission factors for coal and gas based stations and imports, with generation data (and in the case of coal plants fuel consumption data) from the CEA provides the following[15]:

[15] It should be noted that the CEA also provide data on specific secondary fuel oil consumption in coal plants. For conservativeness we have no included these emissions in calculation of the OM and BM.

Table 11: Calculation of the Simple OM

	Generation, GWh			Coal Consumption (kt)			Emissions (tCO2)		
Plant	**2004-5**	**2003-4**	**2002-3**	**2004-5**	**2003-4**	**2002-3**	**2004-5**	**2003-4**	**2002-3**
Coal Plants									
Delhi									
Badarpur	5,464	5,432	5,284	3,732	3,605	3,554	6,912,805	6,677,563	6,583,095
I.P.Stn.(DVB)	921	771	619	789	639	497	1,461,469	1,183,623	920,596
Rajghat(DVB)	696	775	837	541	629	705	1,002,097	1,165,100	1,305,876
Haryana									
Faridabad	869	795	973	822	740	880	1,522,595	1,370,706	1,630,029
Panipat	6,008	5,949	4,994	4,447	4,473	3,718	8,237,204	8,285,364	6,886,873
Punjab									
Bhatinda	1,993	2,553	2,497	1,469	1,835	1,763	2,721,037	3,398,981	3,265,615
Lehra									
Mohabbat	3,308	3,379	2,907	1,995	2,041	1,820	3,695,350	3,780,556	3,371,197
Roper	9,082	8,303	8,246	6,056	5,585	5,418	11,217,564	10,345,128	10,035,793
Rajasthan									
Kota	7,751	6,758	6,551	5,213	4,477		9,656,070	8,292,773	8,038,763
Suratgarh	9,363	8,303	7,289	5,920	4,984		10,965,651	9,231,892	8,104,452
Uttar Pradesh									
Anpara	11,511	11,982	11,693	8,339	8,342	8,074	15,446,378	15,451,935	14,955,517
Harduaganj	632	733	769	670	785	805	1,241,045	1,454,060	1,491,106
Obra	5,550	6,247	6,528	4,761	5,372	5,566	8,818,828	9,950,587	10,309,934
Panki Extn.	1,043	1,065	1,016	913	953	995	1,691,155	1,765,247	1,843,044
Paricha	966	655	961	876	590	847	1,622,620	1,092,860	1,568,903
Tanda (NTPC)	3,320	2,912	2,223	2,596	2,331	1,990	4,808,586	4,317,725	3,686,089
Unchahar (NTPC)	6,781	6,454	6,151	4,604	4,396	4,153	8,528,016	8,142,736	7,692,626
Rihand STPS	7,987	7,958	7,752	4,768	4,742	4,787	8,831,794	8,783,634	8,866,988
Singrauli(STPS)	15,806	15,644	16,168	10,336	9,742	10,213	19,145,433	18,045,163	18,917,600
NCTPP(Dadri)	6,830	6,185	6,043	4,432	4,136	4,005	8,209,419	7,661,137	7,418,485
Gas Plants		Generation, GWh						Emissions (tCO2)	

Delhi						
I.P GT	1,162	957	935	607,662	500,329	488,827
I.P. WHP	378	253	280	197,821	132,271	146,387
Pragata CCGT	2,551	2,405	825	1,333,531	1,257,358	431,318
Haryana						
F'bad CCGT	3,162	2,792	2,697	1,653,073	1,459,686	1,410,019
Jammu & Kashmir						
Pampore GT	24	29	58	12,412	15,161	30,323
Rajasthan						
Ramgarh GT	343	241	161	179,287	125,997	84,172
Ramgarh ST	17	0	0	8,888	0	0
Anta GT (NTPC)	2,785	2,777	2,760	1,456,026	1,451,843	1,442,956
Uttar Pradesh						
Auraiya GT	4,120	4,252	4,272	2,153,820	2,222,988	2,233,444
Dadri GT	5,458	5,062	5,212	2,853,445	2,646,464	2,724,886
Imports		Generation, GWh			Emissions (tCO2)	
From Southern	120	0	0	103,529	0	0
From Eastern	3,043	117	827	3,706,768	143,521	963,905
From Western	320	0	0	365,045	0	0
From North Eastern	0	0	0	0	0	0
Totals	**129,364**	**121,738**	**117,528**	**146,942,241**	**137,062,878**	**133,647,702**
Simple OM				**1.14**	**1.13**	**1.14**
Average Simple OM						**1.133**

The final Simple OM, $EF_{OM, y}$, based on the average of the last three years for which data is available is therefore 1.13 tCO_2/MWh.

In considering the BM we are required to calculate the carbon emissions factor based on an examination of recent capacity additions to the Northern region grid. These capacity additions should be chosen from the greater generation accounted for:

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

The total generation of the grid under consideration is 179662.76 GWh (http://cea.nic.in/god/opm/Monthly_Generation_Report/18col_05_03.pdf), 20% of which is 35932.55 GWh. The five most recent plants only account for 594 GWh and therefore the sample to determine the build margin is selected on the basis of the "power plants capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently". The full set of generating plants in the Northern Region is provided by the CEA generation report (http://cea.nic.in/god/opm/Monthly_Generation_Report/18col_05_03.pdf).

Commissioning dates for all generation units included in the CEA generation report have been obtained. The following table shows in chronological order the commissioning dates for the most recent 20% of commissioned plants and the total generation they supply. For the plants commissioned during 2005 and early 2006 some of the data is not available on the commissioning date, however given that the determination of the sample size includes all these plants their exact order of commissioning is immaterial to the calculation.

The calculation of the BM requires us to undertake a generation weighted average of the emissions factors of the individual plants, this is shown in the following table. We have chosen to calculate the BM using Option 1 therefore the BM emission factor will be held constant over the crediting period chosen. The following equation is applied to calculate the BM emission factor:

$$EF_{BM,y} = \frac{\sum_{i,m} F_{i,m,y} . COEF_{i,m}}{\sum_{mj} GEN_{m,y}}$$

Table 12: Identification of plants in BM

Plant	Capacity addition, MW	Date of addition	Generation, GWh	Emissions, tCO2
Leh. Moh.	210	10/16/1998	1,654	2,313,085
Tanda	110	12/30/1998	830	1,202,146
Unchahar	210	1/15/1999	1,695	2,132,004
Suratgrah	250	2/1/1999	1,873	2,193,130
F'bad CCGT	143	9/26/1999	1,054	551,024
Unchahar	210	10/15/1999	1,695	2,132,004
F'bad CCGT	143	10/18/1999	1,054	551,024

RAPS I-IV	220	6/1/2000	1,361	0
Ranjit Sagar	600	7/1/2000	1,145	0
Ghanvi	11.25	7/30/2000	37	0
F'bad CCGT	143	7/31/2000	1,054	551,024
Suratgrah	250	10/1/2000	1,873	2,193,130
Ghanvi	11.25	12/7/2000	37	0
RAPS I-IV	220	12/23/2000	1,361	0
Panipat	210	3/31/2001	1,467	2,011,410
Malana	86	6/15/2001	270	0
Upper Sindh	70	12/30/2001	98	0
Suratgrah	250	1/15/2002	1,873	2,193,130
Pragati	104.6	3/15/2002	808	422,177
Suratgrah	250	7/31/2002	1,873	2,193,130
Upper Sindh	35	9/30/2002	49	0
Pragati	104.6	11/9/2002	808	422,177
Pragati	121.18	1/31/2003	936	489,096
Baspa	300	6/15/2003	1,193	0
Chamera II	300	7/1/2003	1,347	0
Suratgrah	250	8/19/2003	1,873	2,193,130
Ramgarh GT	37.5	9/15/2003	171	89,644
Ramgarh ST	37.8	9/15/2003	17	8,888
Nathpa Jhakri	250	10/6/2003	852	0
Chenani III	9.8	1/1/2004	23	0
Gumma	3	1/1/2004	4	0
Nathpa Jhakri	250	1/2/2004	852	0
Nathpa Jhakri	250	3/30/2004	852	0
Nathpa Jhakri	250	3/31/2004	852	0
Nathpa Jhakri	250	5/6/2004	852	0
Nathpa Jhakri	250	5/18/2004	852	0
Kota	195	8/1/2004	1,446	1,801,850
WY Canel	14.4	1/1/2005	67	0
Bhakra	75		324	0
Ganguwal	6.1		42	0
Kotla	7.1		41	0
Pong	36		157	0
Badarpar	15		112	91,740
F'bad Extn	15		66	100,551
Baira Siul	18		72	0
Chenani	10		5	0

Obra	68	244	0
H'gang B	25	29	2,280
Ey Canal	6	2	0
Dhauli Gang	280	314	0
Totals		**37,561**	**25,837,776**
BM CEF, tCO2/MWh			**0.688**

Source: List of all plants and generation from CEA generation report. Commissioning data from CEA, state electricity boards and NTPC websites.

The weights applied to the operating and build margin are fixed at 0.5, therefore in order to calculate the combined margin we apply these to the Simple OM and BM as calculated above in line with the following equation:

$$EF_y = w_{OM}.EF_{OM,y} + w_{BM}.EF_{BM,y}$$
$$EF_y = 0.5.EF_{OM,y} + 0.5.EF_{BM,y}$$

The following table shows this calculation arriving at the combined margin of 0.910tCO2/MWh.

Table 13: Calculation of the combined margin

	tCO_2/MWh
Simple OM, $EF_{OM, y}$	1.133
Build margin $EF_{BM, y}$	0.688
Combined margin, EF_y	**0.910**

The following table shows the net generation data for the last 3 years and thus permits us to arrive at the average for the determination of EG_y .

Year	MWh
2003-4	29,359
2004-5	40,794
2005-6	44,201
3 yr average	38,118

Annex 4

MONITORING INFORMATION

In addition to the measures for monitoring listed in section B 7.2 the following systems will be put in place to monitor the project activity.

In terms of the storage of data logbooks will be kept for the generation of power. As outlined the environmental monitoring will be undertaken by qualified independent third party agencies and records of these reports will be kept on site along with the necessary consents from the Uttar Pradesh Pollution Control Board.

All meters will be calibrated annually by an accredited independent third party. The calibration records will be maintained on site.

The Power Plant Manager will be responsible for the collection and storage of the electrical data, supported by the shift engineers and the switchboard attendants. The Chief chemist will be responsible for the environmental testing and measurement of the other parameters required. An energy balance will be carried out by Agrinergy before completion of the annual monitoring reports.

In line with the methodology the calorific value will be calculated yearly but the underlying data will be collected daily. The energy balance will be performed as part of the annual appraisal of the project prior to verification and will be undertaken by Agrinergy. The quantity of biomass will be taken from the reports generated for the state sugar directorate, the RT8C report, which is a statutory requirement for sugar plants.

The bagasse sucrose and moisture content are measured through the use of a polarimeter and a weigher. To measure sucrose content a sample of bagasse is taken, diluted with water, filtered and then the optical rotation of the solution is measured against a standard. The device (a prism) is calibrated against standard optical rotations. The moisture is measured by weighing the sample before and after drying.
The archiving and preservation of records will be in paper and electronic form and these will be held for a minimum of two years after the crediting period.

The monitoring of the project activity will be the responsibility of Dr. A V Singh, based in the head office. The monitored data will be reported through Dr. A V Singh to Agrinergy on a monthly basis for the calculation and estimation of emission reductions. This data will be checked against initial estimates and a summary report will be provided quarterly by Agrinergy. If the project is not performing as expected, on the basis of the monthly data, a report will be sent to BHL outlining where the project is deviating in its generation of emission reductions. Should there be significant changes to the set-up or operation of the plant these will be notified to Agrinergy and amendments to the PDD will be requested through a DOE.

At the end of each year of operation Agrinergy will prepare a monitoring report that will be submitted to a DOE for verification, however visits to the site may be undertaken by Agrinergy during the first year to check that the procedures and monitoring plan are being followed.

The registration of the project activity will be the responsibility of Dr. A V Singh but assistance will be provided by Agrinergy.

Emergency situations

In terms of emergency preparedness the main risk is risk of fire. A fire fighting system is installed at the site, comprising fire hydrants and fire extinguishers. The fire hydrants will be tested daily and the extinguishers will be tested in line with the manufacturer's guidelines. A safety committee has been established at the plant and the Security Officer is the designated Fire Officer. This is again supervised by Dr. A V Singh (Vice President, Environment, Health and Safety – BHL)

Training

Complete training for the operation of the boiler and turbine and their auxiliaries will be provided at the time of commissioning by the manufacturers. A complete set of documentation will be provided to support this training and the on-going operation and maintenance of the equipment. Additional training will be provided to the operators and it is expected that they will gain additional recognised technical qualifications through this training.

- - - - -