PROJECT DESIGN DOCUMENT FORM
FOR CDM PROJECT ACTIVITIES (F-CDM-PDD)
Version 04.1

PROJECT DESIGN DOCUMENT (PDD)

Title of the project activity	Tungabhadra wind power project in Karnataka
Version number of the PDD	6~~5~~.0
Completion date of the PDD	~~01/10/2008~~04/06/2014
Project participant(s)	Wind World (India) Limited~~Enercon (India) Ltd~~
Host Party(ies)	Government of India (Host)
Sectoral scope and selected methodology(ies)	1 : Energy industries (renewable - / non-renewable sources) ACM0002 ver. 6 - Consolidated methodology for grid-connected electricity generation from renewable sources
Estimated amount of annual average GHG emission reductions	49,331

SECTION A. Description of project activity

A.1. Purpose and general description of project activity

>>

Objective of the Project

The objective is development, design, engineering, procurement, finance, construction, operation and maintenance of Tungabhadra 22.8 MW wind power project ("Project") in the Indian state of Karnataka to provide reliable, renewable power to the Karnataka state electricity grid which is part of the Southern regional electricity grid. The Project will lead to reduced greenhouse gas emissions because it displaces electricity from fossil fuel based electricity generation plants.

Nature of Project

The Project harnesses renewable resources in the region, and thereby displacing non-renewable natural resources thereby ultimately leading to sustainable economic and environmental development. Wind World (India) Limited ~~Enercon (India) Ltd~~ ("WWIL~~Enercon~~") will be the equipment supplier and the operations and maintenance contractor for the Project. The generated electricity will be supplied to Karnataka Power Transmission Company Ltd ("KPTCL")/ Mangalore Electricity Supply Company Ltd ("MESCOM") under a long-term power purchase agreement (PPA). The Project is owned Wind World (India) Limited.~~by Enercon (India) Ltd~~.

Formatted: Tab stops: 2.7 cm, Left

Contribution to sustainable development

The Project meets several sustainable development objectives including:

- contribution towards the policy desire of Government of India and Government of Karnataka of incremental capacity from renewable sources;
- contribution towards meeting the electricity deficit in Karnataka;
- CO_2 abatement and reduction of greenhouse gas emissions through development of renewable technology;
- reducing the average emission intensity (SO_x, NO_x, PM, etc.), average effluent intensity and average solid waste intensity of power generation in the system;
- conserving natural resources including land, forests, minerals, water and ecosystems; and
- developing the local economy and create jobs and employment, particularly in rural areas, which is a priority concern for the Government of India;

A.2. Location of project activity

A.2.1. Host Party(ies)

>>

Government of India (Host)

A.2.2. Region/State/Province etc.

>>

The Project is located in the State of Karnataka that forms part of the Southern regional electricity grid of India.

A.2.3. City/Town/Community etc.

>>

The Project is located at Kapattagudda –South, (Kapattagudda Wind Zone),

Villages **Singatalur, Koralahalli and Hammigi**

Taluka **Mundargi**
District **Gadag**
State **Karnataka**

A.2.4. Physical/Geographical location

>>

The information allowing the unique identification and distribution of Wind energy Converters is as follows:

Unique Identification Number	District	Taluka	Village	No. Of WEC
EIL- KGS 01 to EIL- KGS 38	Gadag	Mundargi	Koralahalli	6
			Singatalur	12
			Hammagi	20
Total WEC				**38**

Geographical coordinates:

Unique Identification Number	Loc. No.	Latitude			Longitude		
		Degree	Minutes	Seconds	Degree	Minutes	Seconds
EILKGS 1	1	15	3	27.4	75	52	4.0
EILKGS 2	2	15	3	30.0	75	52	2.0
EILKGS 3	3	15	3	29.9	75	51	57.9
EILKGS 4	4	15	3	32.4	75	51	51.3
EILKGS 5	5	15	3	36.1	75	51	43.0
EILKGS 6	6	15	3	37.3	75	51	39.6
EILKGS 7	7	15	3	38.3	75	51	34.1
EILKGS 8	8	15	3	45.3	75	51	40.0
EILKGS 9	9	15	3	49.2	75	51	39.1
EILKGS 10	10	15	3	52.2	75	51	36.7
EILKGS 11	11	15	3	54.1	75	51	32.7
EILKGS 12	12	15	3	54.3	75	51	16.4
EILKGS 13	13	15	3	58.1	75	51	15.3
EILKGS 14	14	15	4	4.2	75	51	17.2
EILKGS 15	15	15	4	7.5	75	51	14.4
EILKGS 16	16	15	4	5.7	75	51	4.8
EILKGS 17	17	15	4	9.5	75	51	1.6
EILKGS 18	18	15	4	20.9	75	51	0.7
EILKGS 19	19	15	4	23.2	75	50	58.1
EILKGS 20	20	15	4	27.2	75	50	54.0
EILKGS 21	21	15	4	34.3	75	51	5.4
EILKGS 22	22	15	4	36.7	75	50	58.9
EILKGS 23	23	15	4	38.9	75	50	51.6
EILKGS 24	24	15	4	38.1	75	50	40.6
EILKGS 25	25	15	4	37.1	75	50	30.2
EILKGS 26	26	15	4	42.4	75	50	38.5
EILKGS 27	27	15	4	45.6	75	50	35.0
EILKGS 28	28	15	4	48.0	75	50	30.7
EILKGS 29	29	15	4	51.0	75	50	26.8
EILKGS 30	30	15	4	54.5	75	50	22.4
EILKGS 31	31	15	4	57.0	75	50	19.9
EILKGS 32	32	15	5	0.6	75	50	16.6
EILKGS 33	33	15	4	16.5	75	51	3.5
EILKGS 34	34	15	5	4.8	75	50	33.7

Unique Identification Number	Loc. No.	Latitude			Longitude		
		Degree	Minutes	Seconds	Degree	Minutes	Seconds
EILKGS 35	35	15	5	8.0	75	50	30.8
EILKGS 36	36	15	5	11.5	75	50	26.1
EILKGS 37	37	15	5	12.7	75	50	19.3
EILKGS 38	38	15	5	15.5	75	50	16.3

~~The project area extends between latitude 13º 31' & 13º 45' North and longitude 76º 30' & 76º 44' East. The Project is connected to the KPTCL 110/33/11 kV substation at Dambal village. The sites are located at a distance of 200 km from Bangalore by road. The nearest railway station is at Bangalore. A location map is attached at Appendix – 1.~~

A.3. Technologies and/or measures

>>

The Project involves 38-wind energy converters (WECs) of Enercon make (600 kW E-40) with internal electrical lines connecting the Project with local evacuation facility. The WECs generates 3-phase power at 400V, which is stepped up to 33 KV. The Project can operate in the frequency range of 47.5–51.5 Hz and in the voltage range of 400 V ± 12.5%. The other salient features of the state-of-art-technology are as follows:

- Gearless Construction - Rotor & Generator Mounted on same shaft eliminating the Gearbox.
- Variable speed function – has the speed range of 18 to 33 RPM thereby ensuring optimum efficiency at all times.
- Variable Pitch functions ensuring maximum energy capture.
- Near Unity Power Factor at all times.
- Minimum drawal (less than 1% of kWh generated) of Reactive Power from the grid.
- No voltage peaks at any time.
- Operating range of the WEC with voltage fluctuation of -20 to +20%.
- Less Wear & Tear since the system eliminates mechanical brake, which are not needed due to low speed generator which runs at maximum speed of 33 rpm and uses Air Brakes.
- Three Independent Braking System.
- Generator achieving rated output at only 33 rpm.
- Incorporates lightning protection system, which includes blades.
- Starts generation of power at wind speed of 3 m/s.

~~Enercon~~ WWIL has secured and facilitated the technology transfer for wind based renewable energy generation from Enercon GmbH, has established a manufacturing plant at Daman in India, where along with other components the "Synchronous Generators" using "Vacuum Impregnation" technology are manufactured.

A.4. Parties and project participants

Party involved (host) indicates a host Party	Private and/or public entity(ies) project participants (as applicable)	Indicate if the Party involved wishes to be considered as project participant (Yes/No)
Government of India (Host)	Wind World (India) Ltd~~Enercon (India) Ltd.~~	No

A.5. Public funding of project activity

>>

There is no ODA financing involved in the Project.

SECTION B. Application of selected approved baseline and monitoring methodology

B.1. Reference of methodology

>>

The approved consolidated baseline and monitoring methodology **ACM0002 Version 6.0** (19 May 2006) has been used. The titles of these baseline and monitoring methodologies are “Consolidated baseline methodology for grid-connected electricity generation from renewable sources” and “Consolidated monitoring methodology for grid-connected electricity generation from renewable sources.

B.2. Applicability of methodology

>>

The Project is wind based renewable energy source, zero emission power project connected to the Karnataka state grid, which forms part of the Southern regional electricity grid. The Project will displace fossil fuel based electricity generation that would have otherwise been provided by the operation and expansion of the fossil fuel based power plants in Southern regional electricity grid.

The approved consolidated baseline and monitoring methodology ACM0002 Version 6 is the choice of the baseline and monitoring methodology and it is applicable because:

- the Project is grid connected renewable power generation project activity
- the Project represents electricity capacity additions from wind sources
- the Project does not involve switching from fossil fuel to renewable energy at the site of project activity since the Project is green-field electricity generation capacities from wind sources at sites where there was no electricity generation source prior to the Project, and
- the geographical and system boundaries of the Southern electricity grid can be clearly identified and information on the characteristics of the grid is available.

B.3. Project boundary

<table>
<tr><th colspan="2">Source</th><th>GHGs</th><th>Included?</th><th>Justification/Explanation</th></tr>
<tr><td rowspan="3">Baseline scenario</td><td rowspan="3">Electricity generation from power plants connected to the Southern Grid</td><td>CO_2</td><td>Included</td><td>Main emission source</td></tr>
<tr><td>CH_4</td><td>Excluded</td><td>This source is not required to be estimated for wind energy projects under ACM0002</td></tr>
<tr><td>N_2O</td><td>Excluded</td><td>This source is not required to be estimated for wind energy projects under ACM0002</td></tr>
<tr><td rowspan="3">Project scenario</td><td rowspan="3">Electricity generation from the Projects</td><td>CO_2</td><td>Excluded</td><td rowspan="3">Wind energy generation does not have any direct GHG emissions.</td></tr>
<tr><td>CH_4</td><td>Excluded</td></tr>
<tr><td>N_2O</td><td>Excluded</td></tr>
</table>

B.4. Establishment and description of baseline scenario

>>

According to ACM0002, for project activities that do not modify or retrofit an existing electricity generation facility, the baseline scenario is the following:

Electricity delivered to the grid by the project would have otherwise 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 described below.

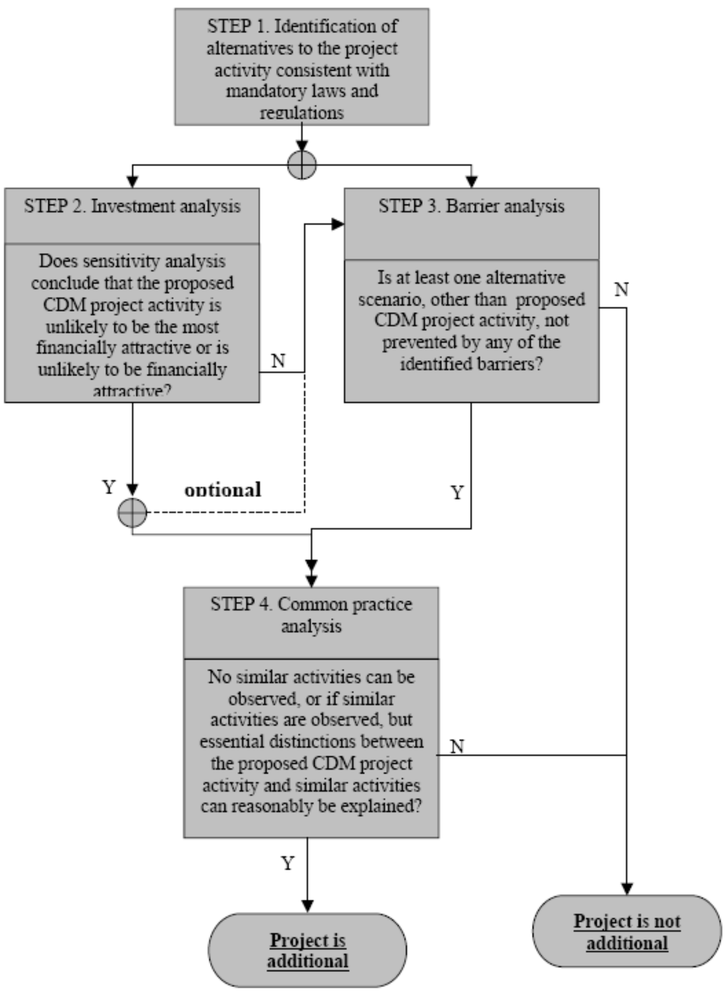
As the Project does not modify or retrofit an existing generation facility, the baseline scenario is the emissions generated by the operation of grid-connected power plants and by the addition of new generation sources. This is estimated using calculation of Combined Margin multiplied by electricity delivered to the grid by the Project.

B.5. Demonstration of additionality

>>

The Project start date will be after the date of validation of the PDD and therefore, no evidence is required. However, ~~Enercon~~WWIL and a CER purchaser had entered into an Emission Reduction Purchase Agreement dated 3 May 2006 for purchase of emission reductions from the Project.

The latest additionality tool i.e. Tool for the demonstration and assessment of additionality version 3.0 approved by CDM Executive Board in its 29th meeting is used to demonstrate project additionality.



Step 1: Identification of alternatives to the project activity consistent with current laws and regulations

Define realistic and credible alternatives to the project activity(s) that can be (part of) the baseline scenario through the following sub-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).

Alternative(s) available to the project participants or similar project developers include:

(a) The Project is not undertaken as a CDM project activity.

(b) Setting up of comparable utility scale fossil fuel fired or hydro power projects that supply to the Karnataka grid under a PPA.

Continuation of the current situation where no project activity or any of the above Alternatives are undertaken would not be applicable as Karnataka had energy (MU) shortages of 0.7% and peak (MW) shortages of 9.8% in 2005-06 (Source: Southern Region Power Sector Profile, August 2006, Ministry of Power).

Outcome of step 1 a:

Alternatives a and b, as identified above are realistic and credible alternatives to the project activity.

Sub-step 1b. Enforcement of applicable laws and regulations

2. The alternative(s) shall be in compliance with all mandatory applicable legal and regulatory requirements, even if these laws and regulations have objectives other than GHG reductions, e.g. to mitigate local air pollution. (This sub-step does not consider national and local policies that do not have legally-binding status.)

3. If an alternative does not comply with all mandatory applicable legislation and regulations, then show that, based on an examination of current practice in the country or region in which the law or regulation applies, those applicable legal or regulatory requirements are systematically not enforced and that non-compliance with those requirements is widespread in the country. If this cannot be shown, then eliminate the alternative from further consideration.

4. If the proposed project activity is the only alternative amongst the ones considered by the project participants that is in compliance with mandatory regulations with which there is general compliance, then the proposed CDM project activity is not additional.

There are no legal and regulatory requirements that prevent Alternatives (a) and (b) from occurring.

Outcome of step 1 b

Both alternative a and alternative b are in compliance with mandatory laws and regulations taking into account the enforcement in the region or country and EB decision on national and sectoral policies. Hence Alternative a and b as identified in the step 1 a are realistic and credible alternatives to the project activity.

Proceed to Step 2 (Investment analysis) or Step 3 (Barrier analysis). (Project participants may also select to complete both steps 2 and 3.)

Step 2: Investment Analysis

Determine whether the proposed project activity is economically or financially less attractive than at least one other alternatives identified in step 1, without the revenue from the sale of certified emission reductions (CERs). To conduct the investment analysis, use the following sub-steps:

Sub-step 2a. - Determine appropriate analysis method

1. Determine whether to apply simple cost analysis, investment comparison analysis or benchmark analysis (sub-step 2b). If the CDM project activity generates no financial or economic benefits other than CDM related income, then apply the simple cost analysis (Option I). Otherwise, use the investment comparison analysis (Option II) or the benchmark analysis (Option III).

Sub-step 2b. – Option I. Apply simple cost analysis

2. Document the costs associated with the CDM project activity and demonstrate that the activity produces no economic benefits other than CDM related income.

Sub-step 2b. – Option II. Apply investment comparison analysis

3. Identify the financial indicator, such as IRR, NPV, cost benefit ratio, or unit cost of service (e.g., levelized cost of electricity production in $/kWh or levelized cost of delivered heat in $/GJ) most suitable for the project type and decision-making context.

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

4. Identify the financial indicator, such as IRR, NPV, cost benefit ratio, or unit cost of service (e.g., levelized cost of electricity production in $/kWh or levelized cost of delivered heat in $/GJ) most suitable for the project type and decision context.

Option I – Simple cost analysis is not applicable as the project activity sells electricity to the grid and obtains economic benefits in the form of electricity tariffs.

~~Enercon~~WWIL proposes to use **Option III – Benchmark analysis** and the financial indicator that is identified is the post-tax return on equity or the equity IRR.

The expected cost of equity and weighted average of cost of capital (WACC) for the power generating industry in India has been calculated using CAPM approach (Detailed calculations are provided in Annex 3~~7~~) supported by data derived from Bloomberg and other relevant sources.

While carrying out the investment analysis, we had initially used the 16% post tax equity return that is considered by state regulatory commissions for determining the tariff applicable to wind power projects. Without CDM revenues, it was not possible for us to implement the project, as the equity IRR of our project was significantly below the industry benchmark as derived from the CAPM model and benchmark; we were able to come close to the benchmark only with the support of CDM revenues. Therefore we entered into a forward emission reduction purchase agreement (ERPA) in December 2005, i.e. before the project start date of January 2007, to secure the CDM revenues and ensure viability of this investment.

In EB-40, the Executive Board ruled against suitability of CERC benchmark of 16% as that value is used in tariff determination for CDM projects and for non CDM projects. We were asked by EB to clarify “Given the calculated IRR for the project activity how it can be demonstrated that investment would not be made without the benefits of CDM”.

We clarified in our submission taken up in EB-41 that, it was not possible for us to undertake the project activity without the benefits of CDM as the IRRs of this project was not only lower than the benchmark, also the IRRs and other factors like Debt Service Coverage Ratio (DSCR) do not meet the credit requirements of banks. To evidence this, we explained the lending criteria applied by bank and how the project was not able to meet these criteria without the support of CDM (please see Annex 1~~5~~ for bank letter). We also drew attention of the EB to the fact that our project IRR was even lower than the bank PLR (Prime Lending Rate). At the time of project start date the Bank PLR was between 11.00% - 11.50% [Source Reserve Bank Web-link http://www.rbi.org.in/scripts/WSSView.aspx?Id=10693], whereas our Project IRR was (without CDM) 9.36%.

Even taking the actual starting interest rate of 8.5% at which the project was approved by lenders, the cushion for them would not have been adequate with Project IRR of just about the same. The Debt Servicing Coverage Ratios (DSCR) of our project in the years 2009, 2010 and 2011 was lower than the DSCR criteria of 1.25x set by the lender of this project (Please see letter from our lender of the project, Rabobank, attached as Annex 1~~5~~) and after adjusting for a 10% downside in generation (which is likely to happen and has happened in the past) the DSCR of our project further comes down in the years 2009, 2010, 2011, 2012 and 2013 lower than the DSCR criteria of 1.25x. With CDM base case the DSCR for complete loan tenure of ten years is coming more than DSCR criteria of 1.25x, which lenders found acceptable.

As per Guidance to investment analysis issued in EB 41 (paragraph 11), the weighted average cost of capital can be considered as appropriate benchmark for project IRR. The tool for demonstration and assessment of additionality [para-5, sub step 2(b)] states that in such cases (where the project has more than one potential developer) the benchmark can not be based on internal cost of equity or WACC and shall be based on parameters that are standard in the market, considering the specific characteristics of the project type. Hence, we have not used company or project specific parameters for the calculation of the benchmark (such as company WACC, project and company specific interest rates, etc.).

Accordingly, the weighted average cost of capital applicable to the project type has been considered. Weighted average cost of capital (WACC) is calculated as weighted average cost of equity and cost of debt as illustrated below

WACC = [D/ (D+E)]*[Cost of Debt] + [E/ (D+E)]*[Cost of Equity]

Cost of Debt:

Cost of debt is defined as the rate at which lender's agree to lend money to a project. The additionality tool and the guidance to investment analysis clarify that for projects that benchmark for project with more than one potential developer should not be based on project specific parameters but should represent the standard in the market. Accordingly, the bank prime lending prevailing at the time of project start date has been considered as the cost of debt. The prime lending rate at the time of investment was in the range of 11.00% - 11.50% [Source Reserve Bank Web-link http://www.rbi.org.in/scripts/WSSView.aspx?Id=10693], the average PLR of 11.00% has been considered as the cost of debt.

Cost of Equity:

The cost of equity has been determined using the Capital Asset Pricing Model (CAPM) considering Beta values of all power generating companies in India that were listed at the time of this investment. Detailed calculations of cost of equity and WACC along with an elaboration of the approach are provided in Annex 3~~7~~.

As can be seen, the benchmark WACC works out to **13.15%.**

The WACC has been calculated considering bank PLR as the cost of debt, this is in accordance with additionality tool version 5 sub-step 2(b) Para 5 that mandates use of standard parameters for benchmark calculation. It may be noted that the actual cost of debt for the project is 8.5%, if the actual cost of debt is considered, the WACC works out to 11.45%.

In accordance with EB guidance (additionality tool version 5 and guidance for investment analysis – EB 41), we have considered the WACC of 13.15 % as the benchmark. However, it is important to note that even if the actual cost of debt were to be considered for WACC calculations, the project IRR is still lower than the WACC.

Sub-step 2c. Calculation and comparison of financial indicators (only applicable to options II and III):

5. Calculate the suitable financial indicator for the proposed CDM project activity and, in the case of Option II above, for the other alternatives. Include all relevant costs (including, for example, the investment cost, the operations and maintenance costs), and revenues (excluding CER revenues, but including *inter alia* subsidies/fiscal incentives, ODA, etc, where applicable), and, as appropriate, non-market cost and benefits in the case of public investors.

6. Present the investment analysis in a transparent manner and provide all the relevant assumptions, preferably in the CDM-PDD, or in a separate annexe to the PDD, so that a reader can reproduce the analysis and obtain the same results. Refer to all critical techno-economic parameters and assumptions (such as capital costs, fuel prices, lifetimes, and discount rate or cost of capital). Justify and/or cite assumptions in a manner that can be validated by the DOE. In calculating the financial indicator, the project's risks can be included through the cash flow pattern, subject to project-specific expectations and assumptions (e.g. insurance premiums can be used in the calculation to reflect specific risk equivalents).
7. Assumptions and input data for the investment analysis shall not differ across the project activity and its alternatives, unless differences can be well substantiated.
8. Present in the CDM-PDD submitted for validation a clear comparison of the financial indicator for the proposed CDM activity and:
   (a) The alternatives, if Option II (investment comparison analysis) is used. If one of the other alternatives has the best indicator (e.g. highest IRR), then the CDM project activity can not be considered as the most financially attractive;
   (b) The financial benchmark, if Option III (benchmark analysis) is used. If the CDM project activity has a less favourable indicator (e.g. lower IRR) than the benchmark, then the CDM project activity cannot be considered as financially attractive.

The key assumptions used for calculating the benchmark (post-tax equity IRR) are set out below. These are the assumption on which the attached financial model based.

Capacity of Machines in kW	600
Number of Machines	38
Project Capacity in MW	22.80
Project Commissioning Date	1-Apr-07
Project Cost per MW (Rs. In Millions)	50.0

Operations	
Plant Load Factor	26.5%
Insurance Charges @ % of capital cost	0.18%
Operation & Maintenance Cost base year @ % of capital cost	1.25%
% of escalation per annum on O & M Charges	5.0%

Tariff	
Base year Tariff for 10 years – Rs./kWh	3.40
Annual Escalation (Rs./kWh per Year)	0.00
Tariff applicable after 10 years (Rs/kWh)	Cost plus 16% return on equity

Project Cost	Rs Million
Land and Infrastructure, Generator & Electrical Equipments, Mechanical Equipments, Civil Works, Instrumentation & Control, Other Project Cost, Pre operative Expenses, etc.	
Total Project Cost	1,140

Means of Finance		Rs Million
Own Source	30%	342
Term Loan	70%	798
Total Source		1,140
Terms of Loan		
Interest Rate	8.50%	
Tenure	10	Years
Moratorium	6	Months

Income Tax Depreciation Rate (Written Down Value basis)	
on Wind Energy Generators	80%
On other Assets	10%
Book Depreciation Rate (Straight Line Method basis)	
On all assets	7.86%
Book Depreciation up to (% of asset value)	90%

Income Tax	
Income Tax rate	30%
Minimum Alternate Tax	10%
Surcharge	10%
Cess	2%

Working capital	
Receivables (no of days)	45
O & m expenses (no of days)	30
Working capital interest rate	12%

CER Revenues	
CER Price in US$	-
Exchange rate Rs./US$*	45.34

* RBI reference rate as of 15 November 2006

Crediting period starts	15-10-07
Length of Crediting period	10

Baseline Emission Factor for Southern Region (tCO2/GWh)	932.04

The equity IRR for the Project (without CDM revenues) is 10.9 % and project IRR is 9.36 %. After considering CDM revenues, the equity and project IRRs improve to 15.44% and 11.32% respectively.

As explained under sub-step 2(b), the benchmark WACC for the project works out to 13.15%, as can be seen the project IRR is lower than the benchmark. Even when the actual cost of debt is considered the project IRR remains lower than the WACC. This analysis holds true even with the sensitivity.

We now present the clarifications to queries raised in EB-41.

Reasons why the project could not have been financed and invested even if the project IRR without CDM (9.36%) was higher than the actual interest rate (8.5%).

We would like to submit that is that this minimal cushion is not enough for lenders, in fact there is virtually no cushion against any downward slide as the numbers are essentially the same. The project IRR is 9.36% whereas the interest rate is 8.5%. When the project IRR is equal to or marginally above the interest rate, the lenders stand the risk of suffering even if there is a small downside in the project's performance. Just a 10% decrease in estimated generation of power (which can easily happen and has happened in the past), the project IRR drops to 7.72% which is lower than the interest rate for the project.

In such cases, lending banks also face the risk of possible increase in interest rates, as any minor variation in interest rate can jeopardize the project's capacity to meet its interest and loan repayment obligations. To illustrate, we would like draw attention to the fact has happened in India from 2005/2006 to the present date. (Please see letter from Rabobank, attached as Annex 2~~6~~). Therefore, to safeguard against reasonable downsides in project performance and changes in interest rate, the project lender considered an average DSCR of at least 1.25x, a project IRR of above 12% which clearly implies that a project IRR marginally above interest rate not enough for them. We have also included a communication from our lenders Rabobank that explains the reasons why banks are not satisfied simply with project IRR being marginally higher than interest rate (Please see letter from Rabobank, attached as Annex 2~~6~~).

Also, projects that generate returns that are barely able to meet the loan costs (leave alone provide any returns to equity investors) are not worthwhile for equity investors like us to invest in. To ensure investment in the project and continued operation, equity investors require an adequate return, and the banks also recognize the same. Please refer to letter from project lender (Rabobank Letter, attached as Annex 1~~5~~) which also mentions the equity IRR criteria for the project.

Principles of Corporate Finance state: Projects raise money from both equity investors and lenders, both groups of investors make their investments expecting to make a return. The expected return for equity investors includes a premium for the equity risk in the investment and is known as Cost of Equity. Similarly; lenders expected return includes a premium for undertaking the risk that the project could default in repayments, and is referred as the Cost of Debt [Page 186, 187 attached as Appendix 11~~5~~]. In fact, "the first principle of Corporate Finance" states that investment should be made only in projects that yield a return greater than the minimum acceptable hurdle rate; the hurdle rate should be higher for riskier projects and should reflect the financing mix" [Page 185, attached as Appendix 10~~4~~]. Therefore the costs of equity and cost of debt, collectively (and not the interest rate alone) represent what the project needs to make on its investment in order for it to be considered as investment worthy.

In summary, Lenders are not willing to finance projects that have financial parameters that are significantly lower than the lending criteria. Further, the parameter for investment is the equity IRR, without which the investor will not invest in any case, and the project will not even be referred to lenders for consideration.

Sub-step 2d. Sensitivity analysis (only applicable to options II and III):

9. Include a sensitivity analysis that shows whether the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions. The investment analysis provides a valid argument in favour of additionality only if it consistently supports (for a realistic range of assumptions) the conclusion that the project activity is unlikely to be the most financially attractive (as per step 2c para 8a) or is unlikely to be financially attractive (as per step 2c para 8b).

Sensitivity analysis of the Equity IRR to the Plant Load Factor (the most critical assumption) has been carried out considering a plant load factor of 23% and 28% (10% variation from the CUF considered by KERC for tariff determination in its Order dated 18 January 2005. Plant Load Factor is the key variable

encompassing variation in wind profile, variation in off-take (including grid availability) including machine downtime. The post tax Equity IRRs at the stated PLFs are as follows:

	PLF at 23%	PLF at 28%
Post tax Equity IRR without CER revenues	6.4%	12.9%
Post tax Project IRR without CER revenues	7.18 %	10.26%

Outcome of step 2

As can be seen from above, the Project is not the most financially attractive (as per step 2c para 8a) we proceed to Step 4 (Common practice analysis).

Step 4. Common practice analysis

Sub-step 4a. Analyze other activities similar to the proposed project activity:
Sub-step 4b. Discuss any similar options that are occurring:

1. Provide an analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity. Projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc. Other CDM project activities are not to be included in this analysis. Provide documented evidence and where relevant quantitative information. On the basis of that analysis, describe whether and to which extent similar activities have already diffused in the relevant region.
2. If similar activities are widely observed and commonly carried out, it calls into question the claim that the proposed project activity is financially unattractive (as contended in Step 2) or faces barriers (as contended in Step 3). Therefore, if similar activities are identified above, then it is necessary to demonstrate why the existence of these activities does not contradict the claim that the proposed project activity is financially unattractive or subject to barriers. This can be done by comparing the proposed project activity to the other similar activities, and pointing out and explaining essential distinctions between them that explain why the similar activities enjoyed certain benefits that rendered it financially attractive (e.g., subsidies or other financial flows) and which the proposed project activity can not use or did not face the barriers to which the proposed project activity is subject.
3. Essential distinctions may include a serious change in circumstances under which the proposed CDM project activity will be implemented when compared to circumstances under which similar projects were carried out. For example, new barriers may have arisen, or promotional policies may have ended, leading to a situation in which the proposed CDM project activity would not be implemented without the incentive provided by the CDM. The change must be fundamental and verifiable.

We analyze the extent to which wind energy projects have diffused in the electricity sector in Karnataka. In 2004 – 05, wind electricity generation was 485.57 GWh and the total electricity availability at bus-bar in the state of Karnataka was 33523.92 GWh (Source: CEA General Review 2006). This shows that wind energy accounted for 1.45% of electricity generation in the state of Karnataka, and was therefore not common practice.

Installed capacity of wind energy generation sources stood at 276 MW as of 31 March 2005 (Source: CEA General Review 2006). There are approximately 201 MW wind energy projects that are currently in the CDM pipeline (UNFCCC website) and more are expected to follow.

Further, all other wind projects in Karnataka to the best of our knowledge, as as per the CDM pipeline, are substantially dependent on CDM mechanism.

Outcome of step 4
Thus wind projects without CDM is not common practice.

Sub-steps 4a and 4b are satisfied and therefore the project activity is additional.

B.6. Emission reductions
B.6.1. Explanation of methodological choices
>>
According to the approved baseline methodology ACM0002, the emission reductions ***ERy*** by the project activity during a given year "*y*[1]" is

ERy = BEy – PEy – Ly……………….(1)

Where: *BEy* is the baseline emissions
PEy is project activity emissions and;
Ly is the amount of emissions leakage resulting from the project activity.

Baseline Emissions for the amount of electricity supplied by project activity, *BEy* is calculated as

BEy = EGy * EFy …………………….(2)

where *EGy* is the electricity supplied to the grid, *EFy* is the CO_2 emission factor of the grid as calculated below.

The emission factor *EFy* of the grid is represented as a combination of the Operating Margin (OM) and the Build Margin (BM). Considering the emission factors for these two margins as $EF_{OM,y}$ and $EF_{BM,y}$, then the *EFy* is given by:

$$EFy = w_{OM} * EF_{OM,y} + w_{BM} * EF_{BM,y} \ldots\ldots (2)$$

with respective weight factors w_{OM} and w_{BM} (where $w_{OM} + w_{BM} = 1$).

The Operating Margin emission factor

[1] Throughout the document, the suffix *y* denotes that such parameter is a function of the year y, thus to be monitored at least annually.

As per ACM0002, dispatch data analysis should be the first methodological choice. However, this option is not selected because the information required to calculate OM based on dispatch data is not available in the public domain for the Southern electricity regional grid.

The Simple Operating Margin approach is appropriate to calculate the Operating Margin emission factor applicable in this case. As per ACM 0002 the Simple OM method can only be used where low cost must run resources constitute less than 50% of grid generation based on average of the five most recent years. The generation profile of the Southern grid in the last five years is as follows:

Generation in GWh	**2004-05**	**2003-04**	**2002-03**	**2001-02**	**2000-01**
Low cost/must run sources					
Hydro	24,951	16,943	18,288	26,260	29,902
Wind & Renewables	3,256	1,865	1,607	1,456	1,262
Nuclear	4,408	4,700	4,390	5,244	4,331
Other sources					
Coal	99,010	98,435	92,053	84,032	83,292
Diesel	2,434	3,295	4,379	4,155	2,868
Gas	12,428	14,214	13,950	10,331	7,132
Total Generation	**146,487**	**139,451**	**134,667**	**131,478**	**128,787**
Low cost/must run sources	32,615	23,508	24,285	32,960	35,496
Low cost/must run sources	22%	17%	18%	25%	28%

Source: Table 3.4 of CEA General Review 2004-05, 2003-04, 2002-03, 2001-02, 2000-01

From the available information it is clear that low cost/must run sources account for less than 50% of the total generation in the Southern grid in the last five years. Hence the Simple OM method is appropriate to calculate the Operating Margin Emission factor applicable.

Build Margin Emission Factor

The Build Margin emission factor *EF_BMy* (tCO_2/GWh) is given as the generation-weighted average emission factor of the selected representative set of recent power plants represented by the 5 most recent plants or the most recent 20% of the generating units built (summation is over such plants specified by k):

$$EF_{BM,y} = [\sum_i F_{i,m,y} * COEFi] / [\sum_k GEN_{k,m,y}] \ldots\ldots\ldots\ldots (5)$$

The summation over *i* and *k* is for the fuels and electricity generation of the plants in sample *m* mentioned above.

The choice of method for the sample plant is the most recent 20% of the generating units built as this represents a significantly larger set of plants for a large regional electricity grid having a large number of power plants connected to it and is therefore appropriate.

The Central Electricity Authority, Ministry of Power, Government of India has published a database of Carbon Dioxide Emission from the power sector in India based on detailed authenticated information obtained from all operating power stations in the country. This database i.e. The CO_2 Baseline Database provides information about the Operating Margin and Build Margin Emission Factors of all the regional electricity grids in India. The Operating Margin in the CEA database is calculated ex ante using the Simple OM approach and the Build Margin is calculated ex ante based on 20% most recent capacity additions in the grid based on net generation as described in ACM0002. We have, therefore, used the Operating Margin and Build Margin data published in the CEA database, for calculating the Baseline Emission Factor.

Combined Margin Emission Factor

As already mentioned, baseline emission factor (EFy) of the grid is calculated as a combined margin (CM), calculated as the weighted average of the operating margin (OM) and build margin (BM) factor. In case of wind power projects default weights of 0.75 for EF_{OM} and 0.25 for EF_{BM} are applicable as per ACM0002. No alternate weights are proposed.

Using the values for operating margin and build margin emission factors provided in the CEA database and their respective weights for calculation of combined margin emission factor, the baseline carbon emission factor (CM) is 932.04tCO2e/GWh or 0.93204 tCO2e/MWh.

Project Emissions:

The project activity uses wind power to generate electricity and hence the emissions from the project activity are taken as nil.

PEy = 0

Leakage:

Emissions Leakage on account of the project activity is ignored in accordance with ACM0002.

Ly = 0

B.6.2. Data and parameters fixed ex ante

Data / Parameter	$EF_{OM,y}$
Unit	tCO2e/MWh
Description	Operating Margin Emission Factor of Southern Regional Electricity Grid
Source of data	"CO2 Baseline Database for Indian Power Sector" published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO2 Baseline Database for Indian Power Sector" is available at www.cea.nic.in
Value(s) applied	2002 – 03: 0.9970 2003 – 04: 1.0094 2004 – 05: 1.0038
Choice of data or Measurement methods and procedures	Operating Margin Emission Factor has been calculated by the Central Electricity Authority using the simple OM approach in accordance with ACM0002.
Purpose of data	To calculate baseline emission factor
Additional comment	None

Data / Parameter	$EF_{BM,y}$
Unit	tCO2e/MWh
Description	Build Margin Emission Factor of Southern Regional Electricity Grid (year 2004-05)
Source of data	"CO2 Baseline Database for Indian Power Sector" published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO2 Baseline Database for Indian Power Sector" is available at www.cea.nic.in
Value(s) applied	2004 – 05 0.7180
Choice of data or Measurement methods and procedures	Build Margin Emission Factor has been calculated by the Central Electricity Authority in accordance with ACM0002.
Purpose of data	To calculate baseline emission factor
Additional comment	None

B.6.3. Ex ante calculation of emission reductions

>>

Ex-ante calculation of emission reductions is equal to ex-ante calculation of baseline emissions as project emissions and leakage are nil.

Baseline emission factor (combined margin)
= 932.04 tCO2e/GWh

Annual electricity supplied to the grid by the Project
= 22.8 MW (Capacity) x 26.5% (PLF) x 8760 (hours) / 1000 GWh
= 52.928 GWh

Annual baseline emissions
= 932.04 tCO2e/GWh x 52.928 GWh
= 49,331 tCO2e

B.6.4. Summary of ex ante estimates of emission reductions

Year	Baseline emissions (t CO_2e)	Project emissions (t CO_2e)	Leakage (t CO_2e)	Emission reductions (t CO_2e)
2008	49,331	0	0	49,331
2009	49,331	0	0	49,331
2010	49,331	0	0	49,331
2011	49,331	0	0	49,331
2012	49,331	0	0	49,331
2013	49,331	0	0	49,331
2014	49,331	0	0	49,331
2015	49,331	0	0	49,331
2016	49,331	0	0	49,331
2017	49,331	0	0	49,331
Total	493,310	0	0	493,310
Total number of crediting years	10			
Annual average over the crediting period	49,331	0	0	49,331

B.7. Monitoring plan
B.7.1. Data and parameters to be monitored

Data / Parameter	**EGy**
Unit	MWh (Mega-Watt hour)
Description	Net electricity supplied to the grid by the Project
Source of data	Electricity supplied to the grid as per Joint Meter Readings (Form B) taken at 33kV metering point
Value(s) applied	Annual electricity supplied to the grid by the Project = 22.8 MW (Capacity) x 26.5% (PLF) x 8760 (hours) MWh = 52.928 MWh
Measurement methods and procedures	Monitoring: The procedures for metering and meter reading will be as per the provisions of the power purchase agreement except or otherwise explicitly stated in the monitoring plan in section B.7.3. Metering system for the project activity consists of one main and check meter at 33 kV metering location. Both meters are two-way tri-vector meters capable of recording import and export of electricity. In addition to this there are two main and check meters (bulk meters) at 110 kV metering point at the ~~Enercon~~WWIL substation at Bannikoppa. The bulk meter is connected to the machines of the project activity and the machines commissioned by the other project developers. Therefore in order to determine the electricity supplied to the grid by the project activity at high voltage (110 kV) side of ~~Enercon~~WWIL substation, the state utility (herein after referred to as "KPTCL/HESCOM") applies the transmission loss between 110 kV metering points (two in number) and meter reading recorded at the 33 kV metering points for all the machines that are connected to 110 kV bulk meters at ~~Enercon~~WWIL substation at Bannikoppa. The transmission loss calculated by the state utility is endorsed / confirmed jointly by the representatives of ~~Enercon~~WWIL and the state utility. The transmission loss applied to the project activity by the state utility is reflected in the JMR (Form B) recorded at 33kV metering point. Refer Appendix 1 for location of meting points at 33kV and 110 kV. Frequency of recording data: Monthly Recording: The values of electricity supplied to the grid is sourced from JMR for 22.8 MW at 33 kV metering point. Responsibility: Joint responsibility of ~~Enercon~~WWIL and state utility. Refer section B.7.3 and Appendix– 5 for an illustration of the provisions for measurement methods.
Monitoring frequency	Frequency of recording data: Monthly Recording: The values of electricity supplied to the grid is sourced from JMR for 22.8 MW at 33 kV metering point.
QA/QC procedures	QA/QC procedures will be as implemented by state utility pursuant to the provisions of the power purchase agreement except or otherwise explicitly stated in the PDD. The values of electricity supplied to the grid mentioned in the JMR for 22.8 MW for the project at 33kV metering point can be cross checked with values mentioned in the invoice raised on the state utility. Refer ~~Annex 4~~Appendix-5 for an illustration of the provisions for QA/QC procedures

Purpose of data	Baseline Emissions calculations
Additional comment	The data (electricity supplied to the grid) will be archived on electronic media as well as on paper. The archive will be kept for the period up to two years after the completion of the crediting period.

Data / Parameter	**EGexport**
Unit	MWh (Mega-Watt hour)
Description	Electricity Export recorded at meters (one main and one check) connecting 38 machines of the project activity.
Source of data	Electricity export to the grid as per joint meter reading (Form B) issued by HESCOM, taken at 33 kV metering point and can be sourced from JMR for 22.8 MW of the project activity.
Value(s) applied	This value will be taken from the JMR (Form B) taken at 33kV metering point and will be applied directly.
Measurement methods and procedures	Monitoring: Electricity export to the grid will be recorded by the meters (one main and one check) connecting 38 turbines at 33kV point. Refer section B.7.3 and ~~Annex-4~~Appendix-5 for an illustration of the provisions for measurement methods. Frequency of recording data: Monthly Recording: The values electricity export to the grid is sourced from one JMR for 22.8 MW at 33 kV metering point. Responsibility: Joint responsibility of ~~Enercon~~WWIL and state utility
Monitoring frequency	Reading frequency: Hourly Frequency of recording data: Monthly Recording: The values of electricity exports to the grid are sourced from JMR for the project at 33 kV metering point.
QA/QC procedures	QA/QC procedures will be as implemented by state utility and the PP except or otherwise explicitly stated in the PDD. Refer Appendix-5 for an illustration of the provisions for QA/QC procedures.
Purpose of data	Baseline Emissions calculations
Additional comment	The data will be archived on electronic media as well as on paper. The archive will be kept for the period up to two years after the completion of the crediting period.

Data / Parameter	EGimport
Unit	MWh (Mega-Watt hour)
Description	Electricity Import recorded at the meters (one main and one check) connecting 38 machines of the project activity.
Source of data	Electricity import from the grid as per joint meter reading issued by HESCOM, taken at 33kV metering point and can be sourced from JMR for 22.8 MW of the project activity.
Value(s) applied	This value will be taken from the JMR (Form B) taken at 33 kV metering point and will be applied directly.
Measurement methods and procedures	Monitoring: Electricity import from the grid will be recorded by meters (one main and one check) connected to the 38 machines at 33kV point. Refer section B.7.3 and ~~Annex-4~~Appendix-5 for an illustration of the provisions for measurement methods. Frequency of recording data: Monthly Recording: The values electricity import to the grid is sourced from one JMR for 22.8 MW at 33 kV metering point. Responsibility: Joint responsibility of ~~Enercon~~WWIL and state utility
Monitoring frequency	Reading frequency: Hourly Frequency of recording data: Monthly Recording: The values of electricity exports to the grid are sourced from JMR for the project at 33 kV metering point.
QA/QC procedures	QA/QC procedures will be as implemented by state utility and the PP except or otherwise explicitly stated in the PDD. Refer section B.7.3 ~~Annex-4~~Appendix-5 for an illustration of the provisions for QA/QC procedures.
Purpose of data	Baseline Emissions calculations
Additional comment	The data will be archived on electronic media as well as on paper. The archive will be kept for the period up to two years after the completion of the crediting period.

Data / Parameter	TE
Unit	MWh (Mega-Watt hour)
Description	Transmission loss for export between the metering location at 33 kV point and the metering location at 110 kV at the ~~Enercon~~WWIL substation.
Source of data	Transmission Loss for export will be sourced from the joint meter reading (Form B) issued by HESCOM, taken at 33kV metering point for the project activity.
Value(s) applied	This value is certified by the State utility in the JMR (Form B). This value will be directly sourced from the JMR (Form B).
Measurement methods and procedures	Monitoring: Transmission loss between metering location at 33 kV and the metering location at 110 kV at ~~Enercon~~WWIL substation is applied to the meter reading taken at meters connected at 33 kV point for the project activity. ~~Enercon~~WWIL Substation is connected to the machines of the project activity and the machines commissioned by the other project owners. Therefore transmission loss is applied by the state utility as reflected in the JMR (Form B) taken at 33kV point. The JMR (Form B) is signed by the representatives of ~~Enercon~~WWIL and the state utility. Refer section B.7.3 and ~~Annex 4~~Appendix-5 for an illustration of the provisions for measurement methods. Frequency of recording data: Monthly Recording: The value of transmission loss is sourced from JMR for 22.8 MW at 33 kV metering point. Responsibility: Joint responsibility of ~~Enercon~~WWIL and state utility Refer section B.7.3 and ~~Annex 4~~Appendix-5 for an illustration of the provisions for measurement methods.
Monitoring frequency	Frequency of recording data: Monthly Recording: The value of transmission loss is sourced from JMR for the project at 33 kV metering point.
QA/QC procedures	QA/QC procedures will be as implemented by state utility and the PP. Refer section B.7.3 and ~~Annex 4~~Appendix-5 for an illustration of the provisions for QA/QC procedures.
Purpose of data	Baseline Emissions calculations
Additional comment	The data will be stored in hard format and values will be taken from JMR.

The data will be stored in hard format and soft format by PP (~~Enercon~~WWIL) at the project site office. Joint meter reading is taken in the presence of the persons representing ~~Enercon~~WWIL [Operation and Maintenance Contractor]. The archive will be kept for the period up to two years after the completion of the crediting period.

B.7.2. Sampling plan

>>

Not applicable

B.7.3. Other elements of monitoring plan

>>

Approved monitoring methodology ACM0002 / Version 06 Sectoral Scope: 1, "Consolidated methodology for grid-connected electricity generation from renewable sources", by CDM - Meth Panel is proposed to be used to monitor the emission reductions.

This approved monitoring methodology requires monitoring of the following:

- Electricity generation from the project activity; and
- Operating margin emission factor and build margin emission factor of the grid, where ex post determination of grid emission factor has been chosen

Since the baseline methodology is based on ex ante determination of the baseline, the monitoring of operating margin emission factor and build margin emission factor is not required. There is one main and check meter dedicated to project activity at 33 kV metering point for the project activity. In addition to this there are two main and check meters (bulk meters) at 110 kV metering point at the ~~Enercon~~WWIL substation and are connected to the machines of the project activity and the machines commissioned by the other project developers. Therefore in order to determine the electricity supplied to the grid by the project at 110 kV at the Bannikoppa substation, the state utility applies the transmission loss to the meter reading recorded at the 33 kV metering point. The transmission loss calculated by the state utility is endorsed / confirmed jointly by the representatives of ~~Enercon~~WWIL and the state utility. The transmission loss applied to the project activity by the state utility is reflected in the JMR (Form B) recorded at 33kV metering point. Electricity supplied to the grid is calculated by applying transmission loss to the meter readings taken at 33 kV metering location of the project activity.

The procedure for calculation of transmission loss as given in the PPA is set-out below:

$$Z = (((X1+X2+X3......+Xn)-Y)*100)/ (X1+X2+X3......+Xn)$$

Z = Percentage transmission loss for export incurred in transmission line between the meter located at 33 kV metering point and the meters located at 110kV metering point (two bulk meters) high voltage side of receiving sub-station.

Xi = Energy Export Reading of energy meter installed at 33kV metering point

Here, Xi represents X1, X2, X3,…Xn which are the meters that are installed at 33kV metering point and are connected to the receiving substation by internally connected lines to the receiving station.

Y = Energy Export Readings at bulk meters (two in number) installed at high voltage side of transformer of the receiving station at 110 kV.

The Export Reading Xi is adjusted for transmission loss that is determined by the state utility and is applied directly to the JMR (Form B) taken at 33 kV metering point. This can be checked from the JMR signed jointly by the representatives of ~~Enercon~~WWIL and the state utility.

Transmission Loss in Export (**T_E**) = Percentage Transmission Loss (Z) * Energy Export at 33kV metering point (EGexport)

Empirical Formula for Energy Export after adjustment of transmission loss (Equation 1)

Net Energy Export after adjustment of transmission loss = **EGexport – Transmission Loss (T_E)**

The transmission loss in export is generally less than 5%. However in case of Energy Import, the state utility conservatively applies adjustment of 15% to the import values noted at 33 kV metering point.

Transmission Loss in Import (**T_I**) = 15% * Energy Import at 33kV metering point (EGimport)

Empirical Formula for Energy Import after adjustment of transmission loss (Equation 2)

Net Energy Import after adjustment of transmission loss = **EGimport +15%*EGimport**
= 115%* EGimport

Therefore Energy Supplied to Grid after adjustment of transmission loss is difference of equation 1 and 2 as given in the JMR (Form B) signed jointly by ~~Enercon~~WWIL and the state utility.

EGy = EGexport – 115%*EGimport – Transmission Loss (T_E)

The Joint meter reading noted at 33 kV metering location contains the following data:-

1. Electricity Export (EGexport)
2. Electricity Import (EGimport)
3. Transmission Loss (T_E) between 33 kV metering point and 110 kV metering point (two bulk meters) at ~~Enercon~~WWIL substation
4. Electricity supplied to the Grid [EGexport-115%*EGimport-T_E]

JMR is signed by the representatives of ~~Enercon~~WWIL and the state utility. The meter readings (both export and import), transmission loss and electricity supplied to the grid are recorded in the JMR (33 kV metering point). Hence all these values will be reproduced from the JMR for calculation of emission reductions.

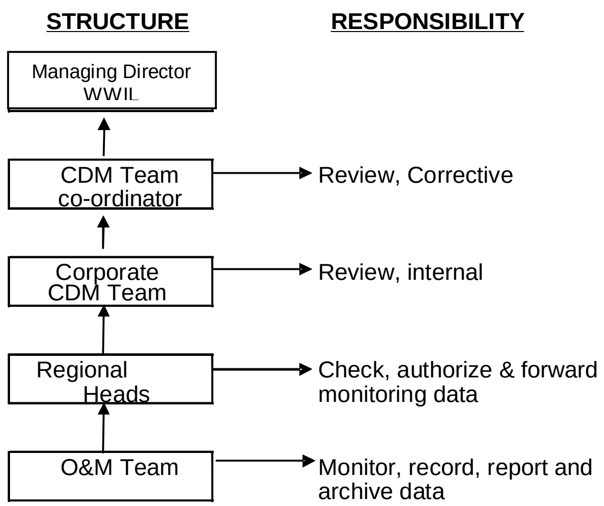
In addition to the JMR (Form B) at 33kV metering location for the project activity, the following documents will also be provided to the DoE for verification:

1. JMR (Form B) at 110kV metering point (two bulk meters) at ~~Enercon~~WWIL substation

2. Transmission loss calculation endorsed / confirmed jointly by the representatives of ~~Enercon~~WWIL and the state utility.

The electricity supplied to the grid can be cross checked from the invoices raised on the state utility for supply of electricity supplied to the grid.

The Project is operated and managed by ~~Enercon~~WWIL. The operational and management structure implemented by ~~Enercon~~WWIL is as follows:



SECTION C. Duration and crediting period

C.1. Duration of project activity

C.1.1. Start date of project activity

>>

01/01/2007 being the commencement /starting date of construction of the project activity.

C.1.2. Expected operational lifetime of project activity

>>

20 years

C.2. Crediting period of project activity

C.2.1. Type of crediting period

>>

Fixed

C.2.2. Start date of crediting period

>>

15/10/2007, being the date on which the Project is expected to be registered.

C.2.3. Length of crediting period

10 years

SECTION D. Environmental impacts

D.1. Analysis of environmental impacts

>>

~~Enercon~~WWIL appointed Aditya Environmental Services Private Limited to conduct Rapid Environmental Impact Assessment study to assess the impact of the project on the local environment.

Environmental Impact Assessment (EIA) of this project is not an essential regulatory requirement, as it is not covered under the categories as described in EIA Notification of 1994 or the Amended Notification of

2006. However, ~~Enercon~~WWIL conducted the EIA to study impacts on the environment resulting from the project activity.

The EIA study included identification, prediction and evaluation of potential impacts of the CDM activities on air, water, noise, land, biological and socio-economic environment within the study area. The ambient air concentrations of Suspended Particulate Matter, respirable Particulate Matter, Oxides of Nitrogen, Sulphur dioxide and Carbon Monoxide were monitored and were found under limits as specified by CPCB. The noise levels were observed throughout the study period and were found to be in the permissible range. Water quality monitoring studies were carried out for determination of physiochemical characteristics of bore wells. The ph level of water was found to be under the specified limits.

The study area represents part of Gadag district. The terrain comprises hilly areas, which are sparingly populated, the hills are generally covered with shrubs and grass, and trees are not found on the hilltops. Moreover the project area doesn't fall under any protected land for wildlife and it has no adverse ecological impacts on the surroundings, flora and fauna found in the vicinity of the project area. The wind-farms do not affect the path of migratory birds.

D.2. Environmental impact assessment

>>

EIA demonstrated that there is no major impact on the environment due to the installation and operation of the windmills. The local ecology is not likely to get impacted by this type of project activity. The local population confirmed that there is no noise or dust nuisance due to windmills. The EIA also ruled out any adverse impacts due to the project activity.

SECTION E. Local stakeholder consultation

E.1. Solicitation of comments from local stakeholders

>>

The comments from local stakeholders were invited through local stakeholder meeting conducted on 15 June 2006 at Panchayat office, Dhoni, Mundaragi in Gadag. An advertisement was placed in a local newspaper in Vijaya Karnataka on 4 June 2006 inviting the local stakeholders for the meeting.

The local stakeholder consultation meeting had representatives from the nearby villages, representatives of ~~Enercon~~WWIL and representative of Aditya Environmental Services (consultant to ~~Enercon~~WWIL). The minutes of the meeting are set out in Appendix 2.

E.2. Summary of comments received

>>

The queries/comments from local villagers in Gadag district covered:

- Comment that wind mills do not impact adversely
- Comment that local labour has been used during construction and operation phase
- Comment that water table has decreased during recent times but not on account of wind mills
- Comment that water supply to agriculture field was not impacted during construction
- Comment that there is no disturbance or high noise level due to operation of the wind mills
- Comment that there have been no accidents and no disturbance or heavy traffic on account of wind mills
- Comment that no dust emissions were observed at project site or in the neighbourhood
- Comment that project has not affected migratory path of birds
- Suggestion that planting of medicinal plants may be carried out at the down plains
- Suggestion that help should be extended to villagers by providing "lift/transportation"
- Suggestion that additional watchmen be deployed to warn of forest fire

E.3. Report on consideration of comments received

>>

~~Enercon~~WWIL provided the following responses in relation to the comments received from the local stakeholders in Gadag district:

- Regarding planting medicinal plants, ~~Enercon~~WWIL is currently doing it at the project site and would also be planting on the slopes.
- Regarding assistance with transport, ~~Enercon~~WWIL would do their best to provide help to the villagers in the emergency cases.
- Regarding forest fire warning/safety, ~~Enercon~~WWIL would be constructing a three feet trench on the slopes and around the project site. It has also instructed watchmen and security guards to be vigilant and provide warning in the cases of occurrences of forest fires.

SECTION F. Approval and authorization

>>

Approval and authorization of Government of India (Host Party) was available at the time of submitting the PDD to the validating DOE.

Approval and authorization of Kingdom of Spain and Swedish Energy Agency (Other Parties) were available at the time of submitting the PDD to the validating DOE. However they were withdrawn at later stage and the current status is present on UNFCCC website.

- - - - -

Appendix 1: Contact information of project participants

Organization name	Wind World (India) Limited~~Enercon (India) Limited~~
Street/P.O. Box	A-9, Veera Industrial Estate, Veera Desai Road, Andheri (West)
Building	Wind World Tower~~Enercon Tower~~
City	Mumbai
State/Region	Maharashtra
Postcode	400 053
Country	India
Telephone	+91-22-~~5522 7794~~66924848
Fax	+91-22-67040473 / 66921177~~5692 1175~~
E-mail	yogesh.mehra@windworldindia.com~~a.raghavan@enerconindia.net~~
Website	www.windworldindia.com
Contact person	Mr. Yogesh Mehra
Title	Managing Director~~Associate Vice President~~
Salutation	Mr.
Last name	Mehra~~Raghavan~~
Middle name	
First name	Yogesh~~A~~
Department	Corporate~~Corporate~~
Mobile	+91-9820040301~~9820045724~~
Direct fax	+91-22-66921177~~5692 1175~~
Direct tel.	+91-22-41017111~~6692 4848 extn. 7169~~
Personal e-mail	yogesh.mehra@windworldindia.com~~a.raghavan@enerconindia.net~~

Appendix 2: Affirmation regarding public funding

The Project activity does not involve any ODA financing.

Appendix 3: Applicability of selected methodology

All details are provided in section B (Application of selected approved baseline and monitoring methodology) of main body of this document.

Appendix 4: Further background information on ex ante calculation of emission reductions

The Operating Margin data for the most recent three years and the Build Margin data for the Southern Region Electricity Grid as published in the CEA database are as follows:

Simple Operating Margin

	tCO2e/GWh
Simple Operating Margin - 2002-03	997.02
Simple Operating Margin - 2003-04	1,009.37
Simple Operating Margin - 2004-05	1,003.76
Average Operating Margin of last three years	1,003.38

Build Margin

	tCO2e/GWh
Build Margin- 2004-05	717.99

Combined Margin calculations

	Weights	tCO2e/GWh
Operating Margin	0.75	1003.38
Build Margin	0.25	717.99
Combined Margin		**932.04**

Detailed information on calculation of Operating Margin Emission Factor and Build Margin Emission Factor is available at www.cea.nic.in.

Appendix 5: Further background information on monitoring plan

The reference of the monitoring information as described under this section has been taken from the PPA.

- **Metering:** Electricity supplied to the grid is metered jointly by state utility and ~~Enercon~~WWIL through one main and one check meter at 33 kV metering point connecting exclusively the machines of project activity.

  In addition to this there are two main and check meters (Bulk meters) at 110 kV metering point at ~~Enercon~~WWIL substation covering machines of the project activity and machines of other project developers. The schematic diagram indicating location of meters at 33 kV and 110 kV metering points for the project activity is attached below.

- **Metering Equipment:** Metering system for the project activity consists of one main and one check meter of 0.2 percent accuracy class at 33kV metering point and two main and check meters at 110 kV metering point. All the meters are **two-way Trivector meters capable of recording import and export of electricity.** The meters installed are capable of recording and storing half hourly readings of all electrical parameters for a minimum period of 35 days with digital output.

- **Meter Readings:** The electricity supplied to the grid is recorded by taking JMR for 22.8 MW at 33kV metering point in the presence of representatives of state utility and ~~Enercon~~WWIL. The JMR at 33kV metering point contains the value of energy exported, energy imported, transmission loss and electricity supplied to the grid during the recording period. This JMR is certified by state utility. These certified readings are then used to prepare the invoices to be raised on Discom. Thus the electricity supplied to the grid as mentioned in the JMR can be crosschecked with the value mentioned in the invoices.

- **Inspection of Energy Meters:** All main and check energy meters and all associated instruments, transformers installed at the Project are of 0.2% accuracy class. Each meter is jointly inspected and sealed on behalf of the Parties and is not to be interfered with by either Party except in the presence of the other Party or its authorized representatives.

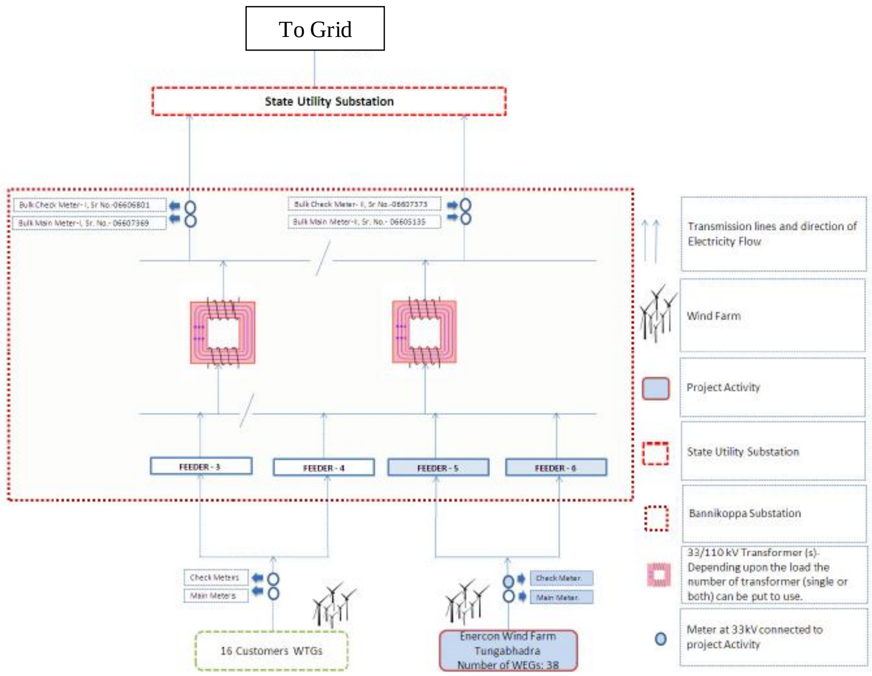
- **Meter Test Checking:** All main and check meters are tested for accuracy with reference to a portable standard meter. The portable standard meter is owned by state utility. The main and check meters shall be deemed to be working satisfactorily if the errors are within specifications for meters of 0.2 accuracy class. The consumption registered by the main meters alone will hold good for the purpose of metering electricity supplied to the grid as long as the error in the main meters is within the permissible limits. All the meters will be tested / calibrated for accuracy annually.

If during the meter test checking,

- The main meter is found to be within the permissible limit of error and the corresponding check meter is beyond the permissible limits, then the meter reading will be as per the main meter as usual. The check meter shall, however, be calibrated immediately.
- The main meter is found to be beyond permissible limits of error, but the corresponding check meter is found to be within permissible of error, then the meter reading for the month up to the date and time of such test shall be as per the check meter. There will be a revision in the meter reading for the period from the previous calibration test up to the current test based on the readings of the check meter. The main meter shall be calibrated immediately and meter reading for the period thereafter till the next monthly meter reading shall be as per the calibrated main meter.
- Both the main meters and the corresponding check meters are found to be beyond the permissible limits of error, both the main meters shall be immediately calibrated and the correction applied to the reading registered by the main meter to arrive the correct reading of energy supplied for metering electricity supplied to the grid for the period from the last month's meter reading up to the current test. Meter reading for the period thereafter till the next monthly reading shall be as per the calibrated main meter.

Training imparted to the Personnel:

~~Enercon~~WWIL has been instrumental in imparting training to the persons it recruits to serve in the organisation. ~~Enercon~~WWIL has a separate training facility, called ~~Enercon~~WWIL Training Academy, which gives training to the persons who are to be deployed On-Site to take care of all the activities starting from project construction to operation to maintenance. The training facility is located at Daman and is fully functional and equipped with qualified trainers, training equipments, classrooms and hostel facilities. The training academy has a fixed schedule which is applicable to all those who reside in the training academy. The training schedule and the training period depend upon the role the trainee has to perform. The trainers are well equipped to judge the capabilities of the trainees.
All trainees, who are to be associated to the technical side of project are given six to twelve months' rigorous training on all the aspects of wind turbine installation and maintenance depending upon the requirements. ~~Enercon~~WWIL conducts periodical test to rate the trainees and thus they are deployed as per the outcomes of their performance during the training period.



Schematic diagram indicating location of meters at 33 kV and 110 kV metering points for the project activity

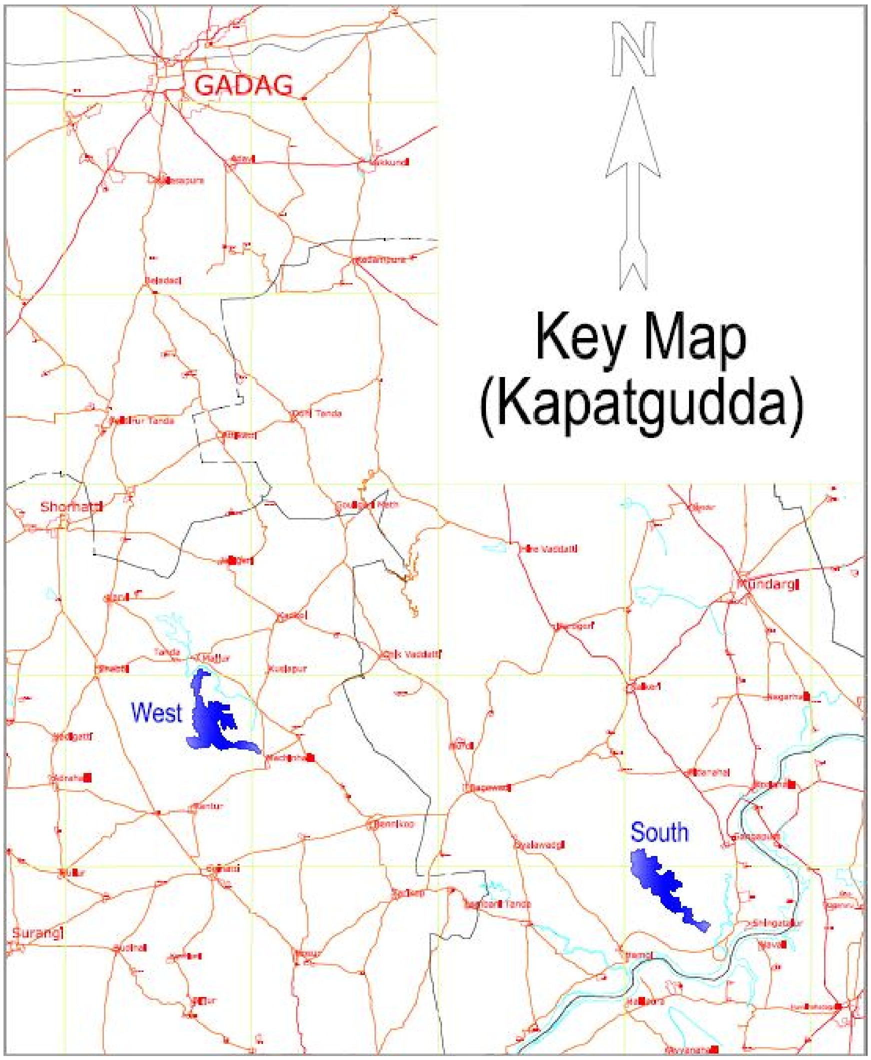
Appendix 6: Summary of post registration changes

- A revision in the monitoring plan has been approved by EB on 18-Feb-2011. Approved revision in in monitoring plan has been incorporated in revised PDD (version 6.0).
- Typographical error in the registered PDD regarding the latitude and longitude details of the turbines have been rectified in revised PDD (version 6.0). The issue regarding the geographical coordinates was raised, by the DOE (TUV NORD) during the first verification of this project activity, and has been discussed under CL R1 on page 21 of the verification report of the 1st monitoring period. The geographical coordinates were revised in the Monitoring report of the 1st monitoring period after seeking a clarification from the UN. During the current verification, the PP has incorporated the same revised coordinates in the revised PDD (version 6.0) in section A.2.4.
- Name change of project proponent from Enercon (India) Limited to Wind World (India) Limited is incorporated.

Formatted: Bulleted + Level: 1 + Aligned at: 0.63 cm + Indent at: 1.27 cm

Formatted: No bullets or numbering

Appendix 7: LOCATION MAP



Appendix 8: – MINUTES OF STAKEHOLDER CONSULTATION MEETING

MINUTES OF THE PUBLIC CONSULTATION STAKEHOLDERS MEETING HELD AT GADAG, KARNATAKA ON 15/06/06

Venue: The meeting is held at Panchayat office, Dhoni, Mundaragi, GADAG, which is about nine km. from the project site.

The meeting has begun at 3:30pm. There are more than forty people attending the meeting. The participants are the people from the villages surrounding the project site- Dambal, Dhoni-Thanda, Kadampura, Katkol, HireVaddatti. Other participants are the panchayat officials- President and Vice President, Representatives from ~~Enercon~~WWIL, and CARE SUSTAINABLILTY

The language of meeting is Kannada. In between Hindi was also used.

The meeting began with the appointment of chairman for the meeting Mr. K.S. Narayanpur. The agenda for the meeting has been as follows:

- Welcome to the participants (by representatives from ~~Enercon~~WWIL)
- Brief to the participants about the project and CLEAN DEVELOPMENT MECHANISM (CDM)
- Questions and answers: concerns/issues/comments/ about the project and related matters by the participants
- Response from ~~Enercon~~WWIL
- Announcement by the representatives of ~~Enercon~~WWIL
- Vote of thanks

The list of the participants with their names and signature are in attached sheet.

The meeting proceeded as per agenda

Table below gives the concerns/issues/comments from the participants and response from ~~Enercon~~WWIL

Sr. No	Questions/concerns/issues/comments relating to the CDM activity	Details of concerns/issues/comments expressed by the participants	Response from ~~Enercon~~WWIL
1	How does the project impact the general quality of the people	All participants expressed that the establishment of the wind units do not adversely affect them (villagers around the project). In brief the projects neither adversely nor bring significant benefits to them. All of them expressed they are happy with the project activity	-
2	Any impact on the livelihood of the villagers	Villagers expressed that their livelihood have not been impacted adversely by the establishment of the wind units. The hill tops or slopes have not been used by them for grazing the cattle.	-

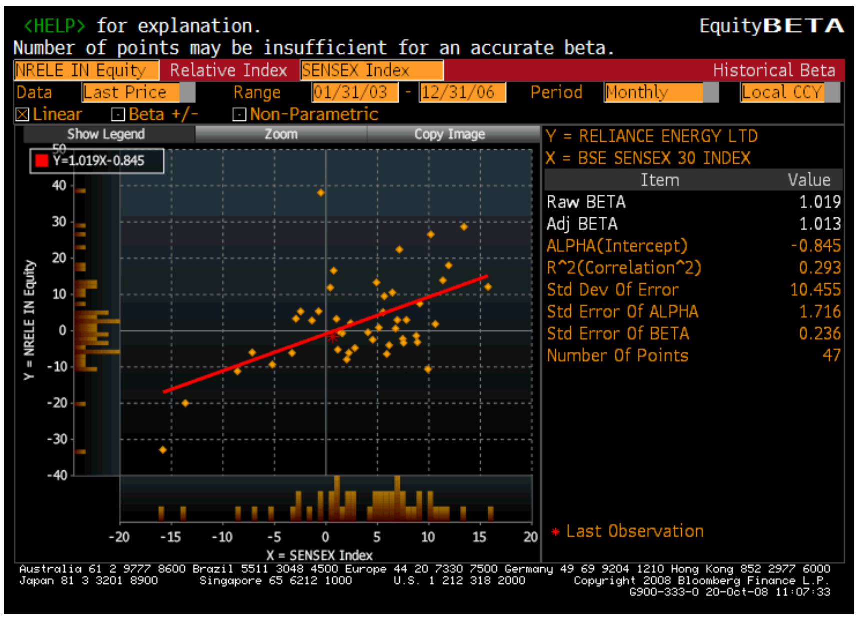
3	Does the project increase the employment opportunities	The following facts have been given by the villagers. During the construction stage, most of the laborers have been locals. During operation stage, at present out of the six local technical staff, two of them at present are locals. All security staff are locals. The drivers are locals.	For locals with ITI (technical training) qualifications, ~~Enercon~~WWIL does provide employment in technical category. Most of the unskilled workers are locals.
4	Does the project improves the electricity supply to villagers/ neighborhood areas	Improvements in the voltage fluctuations and supply are observed. KPCL has established a Sub Station at Dambal There are more than six hundred water pumps (for agricultural activities) in the neighborhood. Operations of them have become for time and without fluctuations at present	Conditions of electricity and voltage fluctuations have improved this year compared to last year, and is expected to improve further. Only KPCL and ~~Enercon~~WWIL have the functioning wind units at the present.
5	Would the project result in drinking water shortage/ increase in shortage of water for agriculture	Water Table has decreased in recent times in the neighborhood agricultural areas. Villagers themselves have expressed that this is not due to the establishment of wind units, but due to the increase in the agricultural activities and number of bore wells in the areas.	-
6	Would the erection of the wind unit result in stoppage of water to agricultural field	Villagers expressed that no stoppage of the water due to the construction of the units and the approach roads to the wind units.	-
7	Would the project increase the noise level in the neighborhood areas and affect the villagers	Villagers expressed that there is no disturbance nor high noise levels are present due to the operation of the wind units	-
8	Any occurrence of accidents. Would the project increase undesirable vehicular traffic during construction or during operation phase	Villagers expressed that no accidents so far have occurred. Also no disturbance or heavy traffic due to the establishment of wind units	-
9	Would the project increase dust particles	During the construction nor the operation stage, no dust emissions are observed in the project sites nor the neighborhood	-
10	Tree/ plantations	Villagers suggested that planting of the medicinal plants could be carried out at the down plains.	~~Enercon~~WWIL is planting medicinal plants at the project

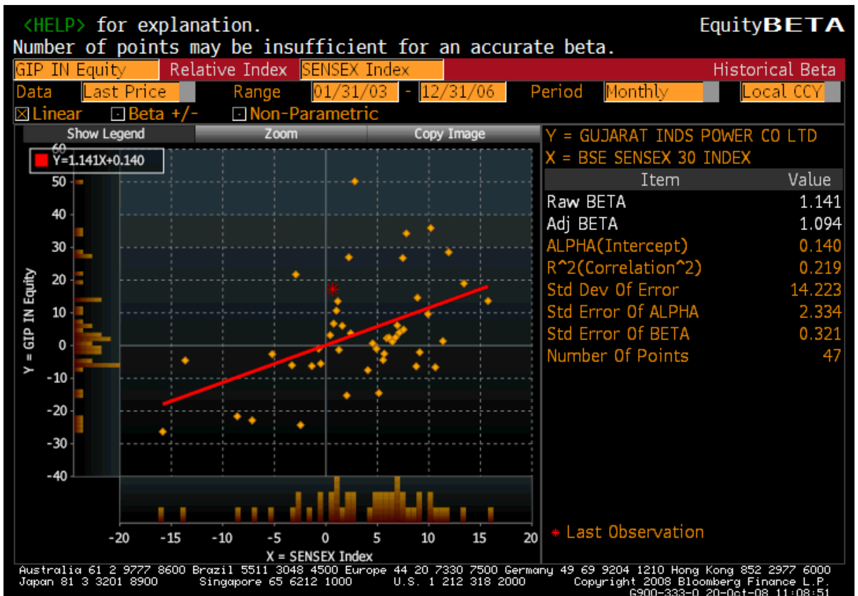
			site. They would also be planting on the slopes.
11	Social welfare activities	Villagers expressed that help should be extended to villagers by providing "lifts"/transportation, when they request during cases like "deliveries" cases etc.	~~Enercon~~WWIL would do their best ot provide help to the villagers in the emergency cases.
12	Forest fire	Villagers expressed fear about the occurrence of forest fire on the hills. (last year there was heavy forest fire on the hill tops). **"Kalpatamallaiah"** temple which is worshipped by the villagers is located on the hill. There should be additional watchmen to be deployed by ~~Enercon~~WWIL for warning the villagers in the event of forest fire.	~~Enercon~~WWIL told about the efforts being made by them. They would be constructing a three feet trench on the slopes and around the project site. Also watchmen and security guards have been instructed to be vigilant and provide warning in the cases of occurrences of forest fires
13	Does any disturbance to Avi fauna occur due to the wind units?	Villagers expressed that due to the increased usage of pesticide in the agricultural areas in the neighbourhood there is a decrease in the birds due to the lack of insects/worms etc. There is no bird's migratory path in the areas	-

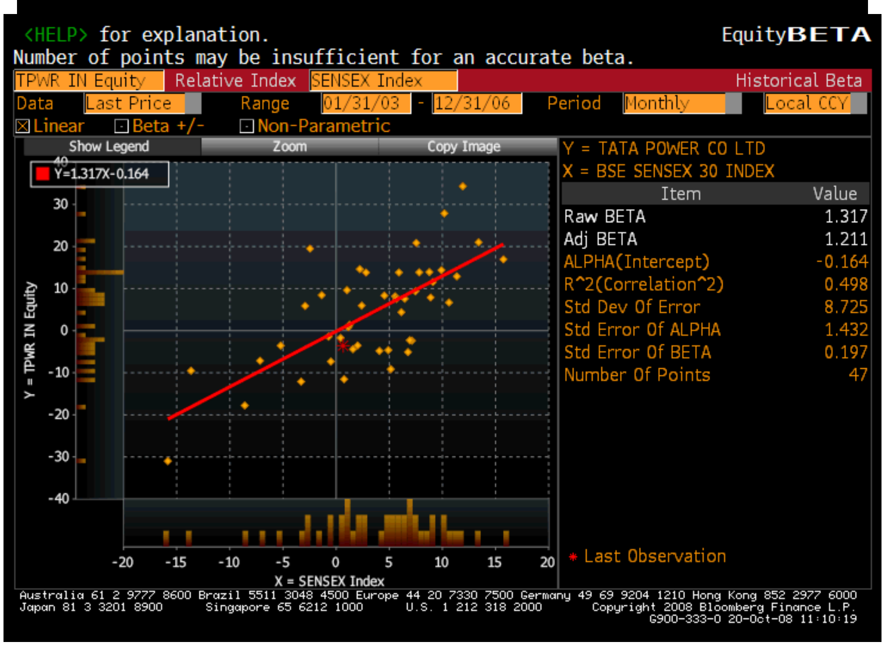
The representative of ~~Enercon~~WWIL announced that if the villagers or the participants stiil wish to bring to notice of ~~Enercon~~WWIL any further issues/concerns/comments about the wind farms owned by ~~Enercon~~WWIL, they may approach and convey to their respective representative Mr. Mahesh Arali located at the project site. The response could be made during the next one month starting from the sate of 15/06/06

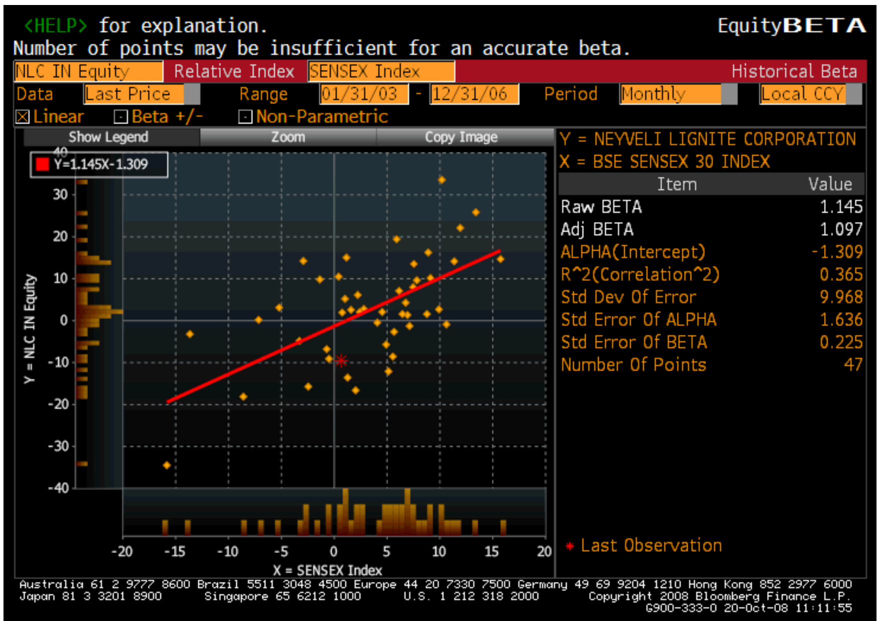
The meeting closed with giving thanks to all the participants and the chairman of the meeting.

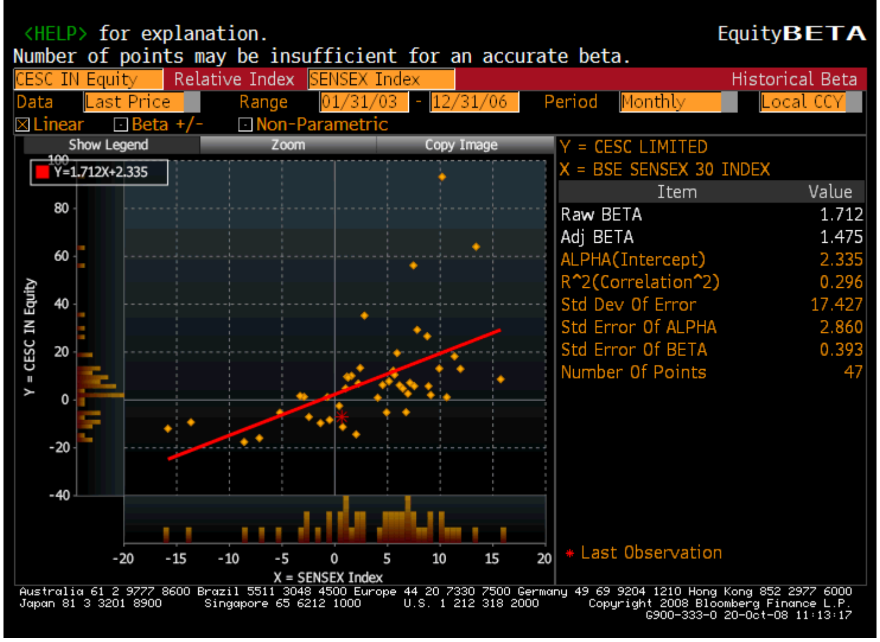
Appendix 9: Bloomberg's screenshots of individual companies for Beta Value

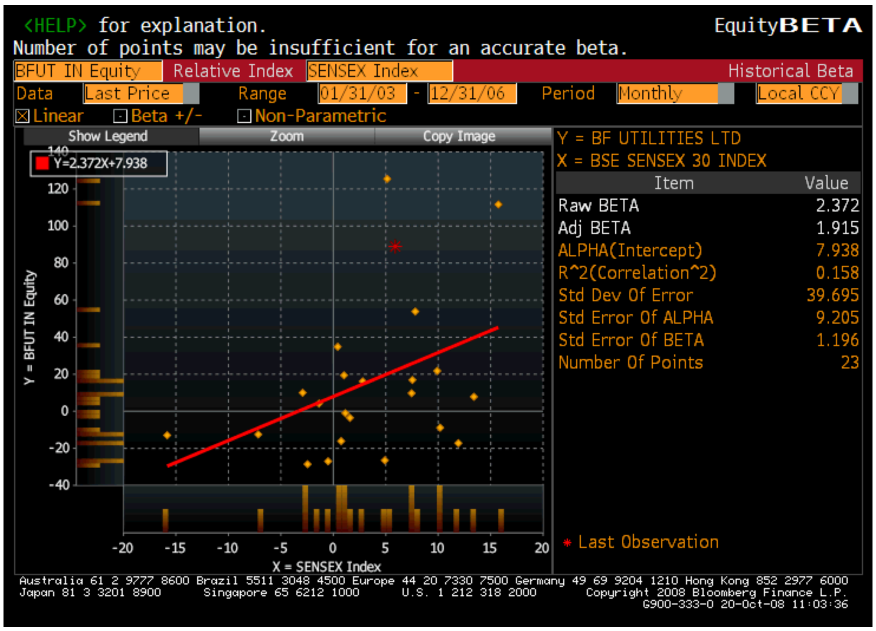



<HELP> for explanation.
EquityBETA
Number of points may be insufficient for an accurate beta.
GIP IN Equity
Relative Index
SENSEX Index
Historical Beta
Data
Last Price
Range
01/31/03 - 12/31/06
Period
Monthly
Local CCY
Linear
Beta +/-
Non-Parametric
Show Legend
Zoom
Copy Image
Y=1.141X+0.140
Y = GIP IN Equity
X = SENSEX Index
Y = GUJARAT INDS POWER CO LTD
X = BSE SENSEX 30 INDEX
Item Value
Raw BETA 1.141
Adj BETA 1.094
ALPHA(Intercept) 0.140
R^2(Correlation^2) 0.219
Std Dev Of Error 14.223
Std Error Of ALPHA 2.334
Std Error Of BETA 0.321
Number Of Points 47
Last Observation
Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2008 Bloomberg Finance L.P.
G900-333-0 20-Oct-08 11:08:51


<HELP> for explanation.
EquityBETA
Number of points may be insufficient for an accurate beta.
TPWR IN Equity
Relative Index
SENSEX Index
Historical Beta
Data
Last Price
Range
01/31/03 - 12/31/06
Period
Monthly
Local CCY
Linear
Beta +/-
Non-Parametric
Show Legend
Zoom
Copy Image
Y=1.317X-0.164
Y = TPWR IN Equity
X = SENSEX Index
Y = TATA POWER CO LTD
X = BSE SENSEX 30 INDEX
Item Value
Raw BETA 1.317
Adj BETA 1.211
ALPHA(Intercept) -0.164
R^2(Correlation^2) 0.498
Std Dev Of Error 8.725
Std Error Of ALPHA 1.432
Std Error Of BETA 0.197
Number Of Points 47
Last Observation
Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2008 Bloomberg Finance L.P.
G900-333-0 20-Oct-08 11:10:19


<HELP> for explanation.
EquityBETA
Number of points may be insufficient for an accurate beta.
NLC IN Equity
Relative Index
SENSEX Index
Historical Beta
Data
Last Price
Range
01/31/03 - 12/31/06
Period
Monthly
Local CCY
Linear
Beta +/-
Non-Parametric
Show Legend
Zoom
Copy Image
Y=1.145X-1.309
Y = NLC IN Equity
X = SENSEX Index
Y = NEYVELI LIGNITE CORPORATION
X = BSE SENSEX 30 INDEX
Item Value
Raw BETA 1.145
Adj BETA 1.097
ALPHA(Intercept) -1.309
R^2(Correlation^2) 0.365
Std Dev Of Error 9.968
Std Error Of ALPHA 1.636
Std Error Of BETA 0.225
Number Of Points 47
Last Observation
Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2008 Bloomberg Finance L.P.
G900-333-0 20-Oct-08 11:11:55


<HELP> for explanation.
EquityBETA
Number of points may be insufficient for an accurate beta.
CESC IN Equity
Relative Index
SENSEX Index
Historical Beta
Data
Last Price
Range
01/31/03 - 12/31/06
Period
Monthly
Local CCY
Linear
Beta +/-
Non-Parametric
Show Legend
Zoom
Copy Image
Y=1.712X+2.335
Y = CESC IN Equity
X = SENSEX Index
Y = CESC LIMITED
X = BSE SENSEX 30 INDEX
Item Value
Raw BETA 1.712
Adj BETA 1.475
ALPHA(Intercept) 2.335
R^2(Correlation^2) 0.296
Std Dev Of Error 17.427
Std Error Of ALPHA 2.860
Std Error Of BETA 0.393
Number Of Points 47
Last Observation
Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2008 Bloomberg Finance L.P.
G900-333-0 20-Oct-08 11:13:17


<HELP> for explanation.
EquityBETA
Number of points may be insufficient for an accurate beta.
BFUT IN Equity
Relative Index
SENSEX Index
Historical Beta
Data
Last Price
Range
01/31/03 - 12/31/06
Period
Monthly
Local CCY
Linear
Beta +/-
Non-Parametric
Show Legend
Zoom
Copy Image
Y=2.372X+7.938
Y = BFUT IN Equity
X = SENSEX Index
Y = BF UTILITIES LTD
X = BSE SENSEX 30 INDEX
Item Value
Raw BETA 2.372
Adj BETA 1.915
ALPHA(Intercept) 7.938
R^2(Correlation^2) 0.158
Std Dev Of Error 39.695
Std Error Of ALPHA 9.205
Std Error Of BETA 1.196
Number Of Points 23
Last Observation
Australia 61 2 9777 8600 Brazil 5511 3048 4500 Europe 44 20 7330 7500 Germany 49 69 9204 1210 Hong Kong 852 2977 6000
Japan 81 3 3201 8900 Singapore 65 6212 1000 U.S. 1 212 318 2000 Copyright 2008 Bloomberg Finance L.P.
G900-333-0 20-Oct-08 11:03:36

Appendix 10: Page 185 of text book on "Corporate Finance Theory and Practice"

PART TWO

Investment Analysis

First Principles of Corporate Finance

Invest in projects that *yield* ***a*** *return greater* than the ***minimum accepable hurdle rate.***
- **The hurdle** rate should be ***higher for riskier projects*** and should reflect the ***financing mix*** used — either owners' funds (equity) **or** borrowed money (debt).
- Returns on projects should be measured on the basis of *cash flows* generated and the *timing* of these cash flows; they should also take into account both *positive and negative side effects* of these projects.

↓

Choose a *financing mix* that *maximizes the value of the firm* and *matches the assets* being financed.

↓

If there are not enough investments that earn the hurdle rate, *return the cash* to the owners of the firm.
The *form of returns* — dividends and stock buybacks — will depend on the *stockholders' characteristics*.

↓

Objective: Maximize the Value of the Firm.

Appendix 11: Page 186-187 of text book on "Corporate Finance Theory and Practice"

CHAPTER 7

Estimating Hurdle Rates for Firms

WHEN ANALYZING firms, we would like to know the cost of raising funds from equity investors (cost of equity), the interest rates they have to pay when they borrow (cost of debt), and their overall cost of financing their operations (cost of capital). Why? Knowing that Boeing's cost of equity is 10.38% and that its cost of capital is 9.17% is a necessary input to value the equity in the firm or the firm itself. In addition, Boeing cannot assess the quality of its existing investments or how much to pay in dividends without knowing how much it costs it to raise funds.

How do we estimate the cost of raising funds from equity investors? In the last chapter, we laid the groundwork for this process. We argued that only that portion of a firm's risk that cannot be diversified away should be considered to be the equity risk in the firm, and that the expected return on an equity investment should reflect this risk. The risk and return models developed in the last chapter provide ways of measuring this risk, and we use these risk measures to come up with expected returns. Although they might vary in the details, these models all require three inputs — a riskless rate, a beta or betas, and a risk premium or premiums. In this chapter, we consider the best ways to estimate these inputs and use them to estimate the expected return on an equity investment. Since investors in equity in a firm require this return to compensate for equity risk, the expected return is also the cost of equity to the firm.

To estimate the cost of debt, we draw on our description of default risk from the last chapter. We consider approaches that can be used to assess the default risk in a firm and how these measures of default risk can be used to compute a cost of debt for the firm.

Because firms use both debt and equity to finance their investments, we examine how much of each the firm uses, yielding an overall cost of financing, that is a weighted average of the costs of equity and debt. This overall cost of financing is the cost of capital to the firm.

The Cost of Equity and Capital

Firms raise money from both equity investors and lenders to fund investments. Both groups of investors make their investments expecting to make a return. In the last chapter, we stated that the expected return for equity investors would include a premium for the equity risk in the investment. We label this expected return the **cost of equity.** Similarly, the expected return that lenders hope to make on their

investments includes a premium for default risk, and we call that expected return the **cost of debt.** If we consider all of the financing that the firm takes on, the composite cost of financing will be a weighted average of the costs of equity and debt, and this weighted cost is the **cost of capital.**

In this chapter, we use the models that we introduced in the last chapter to estimate the costs of equity and capital for firms. In particular, we look at Boeing, The Home Depot, and InfoSoft and evaluate what it costs them to raise equity, debt, and capital. We begin by estimating the equity risk in each of these firms and using the equity risk to estimate the cost of equity, and we follow up by measuring the default risk to estimate a cost of debt. We conclude the chapter by determining the weights we should attach to each of these costs to arrive at a cost of capital.

Why Do We Need Hurdle Rates for Firms?

Why do firms need to know their costs of equity and capital? One of the fundamental decisions that every business needs to make is to assess where to invest its funds and to reevaluate, at regular intervals, the quality of its existing investments. The investment principle, stated in Chapter 1, specifies that firms should invest in assets only if they expect them to earn more than their hurdle rates. The costs of equity and capital for a firm represent what the firm needs to make *collectively on all its investments* in order for them to be good investments. For instance, if The Home Depot's cost of capital is 9.51%, it has to make at least 9.51% on the capital it has invested in all its existing investments. Alternatively, considering the equity investors' perspective alone, The Home Depot with a cost of equity of 9.78% has to earn at least 9.78% on the equity it has invested in all its existing investments for these to be considered good investments. It is worth emphasizing, however, that this does not imply that every project The Home Depot takes will be measured against these criteria, since projects within a firm can have varying degrees of risk. We consider project-specific costs of equity and capital in the next chapter.

Knowing a firm's cost of equity and capital also allows us to compare different ways of financing its operations. We can change the mix of debt and equity at Boeing, for instance, and examine the effects, if any, on the cost of capital for the firm. Increasing the proportion of debt at the firm may allow us to lower the cost of capital from its existing level of 9.17%, letting the firm accept more investments.

In Chapter 5, we noted that the value of a business is computed by discounting the expected cash flows from the business at the cost of capital. We also measured the value of equity by discounting the expected cash flows to equity investors at the cost of equity. Given that our objective in making decisions is to maximize the value of the business, and by extension, the value of the stock (equity), the costs of equity and capital become fundamental inputs into the decision process.

CT 7.1: As long as firms are growing rapidly, they do not need to know their costs of equity or capital. Is this statement true? Why or why not?

Cost of Equity

The cost of equity is the rate of return investors require on an equity investment in a firm. The risk and return models described in the previous chapter need a riskless rate

Appendix 12: Page 190 of text book on "Corporate Finance Theory and Practice"

- If no such securities exist in the market in which you are attempting to estimate a real riskless rate, it can be approximated by the long-term real growth rate of the economy. Thus, the real riskless rate in China may be set equal to 6% because that is what you expect the long-term real growth rate in the Chinese economy to be. It will be much lower (2–3%) for more mature, slower growth economies.

Risk Premium

The risk premium is a significant input in all the asset pricing models. In the following section, we begin by examining the fundamental determinants of risk premiums and then look at practical approaches to estimating these premiums.

What Is the Risk Premium Supposed to Measure? The risk premium measures the "extra return" that would be demanded by investors for shifting their money from a riskless investment to an average risk investment. It should be a function of how risk-averse investors are and how risky they perceive stocks (and other risky investments) to be, relative to a riskless investment. Because each investor in a market is likely to have a different assessment of an acceptable premium, the premium will be a weighted average of these individual premiums, where the weights will be based on the wealth the investor brings to the market. Investors with more wealth, like Warren Buffett, will therefore have their risk premiums weighted more than investors with less wealth.

CQ 7.1: Assume that stocks are the only risky assets and that you are offered two investment options. One is a riskless investment on which you can make 6.7%, and the other is a stock mutual fund. How much more than 6.7% would you need to be offered, on an expected basis, to pick the latter? Would you ever settle for less than 6.7%?

Estimating Risk Premiums We look now at two ways to estimate the risk premium in the capital asset pricing model. One is to look at the past and estimate the premium earned by risky investments (stocks) over riskless investments (government bonds); this is called the **historical premium.** The other is to use the premium extracted by looking at how markets price risky assets today; this is called an **implied premium.**

Historical Risk Premiums. The most common approach to estimating the risk premium is to base it on historical data. In the arbitrage pricing model and multifactor models, the raw data on which the premiums are based are historical data on asset prices over very long time periods. In the CAPM, the premium is estimated by looking at the difference between average returns on stocks and average returns on riskless securities over an extended period of history.

In most cases, we follow these steps to find historical risk premiums. First, we define a time period for the estimation, which can range as far back as 1926 for U.S. data.[4] Then, we calculate the average returns on stocks and average returns on a riskless security over the period. Finally, we calculate the difference between the returns

[4] The most widely used database, from Ibbotson Associates, has returns going back to 1926. Jeremy Siegel at Wharton recently presented data going back to the early 1800s.

Appendix 13: Page 191 of text book on "Corporate Finance Theory and Practice"

on stocks and the riskless return and use it as a risk premium to predict future returns. When we use historical premiums, we implicitly assume that the risk aversion of investors has not changed across time and that the relative riskiness of the risky portfolio (stocks) has not changed over time either.

In calculating the average returns over past periods, a measurement question arises: Should we use arithmetic or geometric averages to compute the risk premium? The arithmetic mean is the average of the annual returns for the period under consideration, whereas the geometric mean is the compounded annual return over the same period. The following example demonstrates the difference.

Year	*Price*	*Return*
0	\$50	
1	100	100%
2	60	−40%

The arithmetic average return over the two years is 30%, while the geometric average is only 9.54% ($1.2^{0.5} - 1 = 1.0954$). Those who use the arithmetic average premium argue that it is much more consistent with the framework[5] of the CAPM and a better predictor of the risk premium in the next period. The geometric mean is justified on the grounds that it takes into account compounding and that it is a better predictor of the average premium in the long term. There can be substantial differences in risk premiums based on the choices made at this stage, as illustrated in Table 7.1. The data in the table are based on historical data on stock, treasury bill, and treasury bond returns and provide estimates of historical risk premiums. As you can see, the historical premiums can vary widely depending on whether we go back to 1926, 1962, or 1981, whether we use T. Bills or T. Bonds as the riskless rate, and whether we use arithmetic or geometric average premiums.[6] Although it is impossible to prove one premium right and the others wrong, we are biased toward

- *Longer term premiums,* since stock returns are volatile and shorter time periods can provide premiums with large standard errors. For instance, the premium extracted from 25 years of data will have a standard error[7] of about 4 to 5%.
- *Long-term bond rates as riskless rates,* since our time horizons in corporate financial analysis tend to be long term, and we use the treasury bond rate as our riskless rate.
- *Geometric average premiums,* since arithmetic average premiums overstate the expected returns over long periods.[8] The geometric mean yields lower premium

[5] The CAPM is built on the premise of expected returns being averages and risk being measured with variance. Since the variance is estimated around the arithmetic average, and not the geometric average, it may seem logical to stay with arithmetic averages to estimate risk premiums.

[6] Booth (1999) examines both nominal and real equity risk premiums from 1871 to 1997. Although the nominal equity returns have changed over time, he concludes that the real equity return has been about 9% over this period. He suggests adding the expected inflation rate to this number to estimate the expected return on equity.

[7] Assuming that returns in individual years are independent, the standard error of a 25-year estimate can be calculated by dividing the annual standard deviation in stock prices in the United States (about 25%) by the square root of the number of years ($\sqrt{25} = 5$), yielding a standard error of 5% (25%/5) in the estimate.

[8] When we look at markets like the United States that have survived for 70 years without significant breaks, we are looking at the exception. To provide a contrast, consider the other stock markets in which one could have invested in 1926; many of these markets did not survive, and an investor would have lost much of his or her wealth.

Appendix 14: Page 196 of text book on "Corporate Finance Theory and Practice"

196 CHAPTER SEVEN / ESTIMATING HURDLE RATES FOR FIRMS

Betas

The second set of inputs that we need to put risk and return models into practice are the betas for investments. In the CAPM, the beta of an investment is the risk that the investment adds to a market portfolio. In the APM and multifactor model, the betas of the investment relative to each factor have to be measured. Three approaches are available for estimating these parameters. One is to use historical data on market prices for individual investments; the second is to estimate the betas from the fundamental characteristics of the investment; and the third is to use accounting data. We describe all three approaches in this section.

Historical Market Betas The conventional approach to estimating the beta of an investment is a regression of returns on the investment against returns on a market index. For firms that have been publicly traded for a length of time, it is relatively straightforward to estimate returns that an investor would have made by investing in the firm's stock each interval (such as a week or a month) over that period. In theory, these stock returns on the assets should be related to returns on a market portfolio, that is, a portfolio that includes all traded assets, to estimate the betas of the assets. In practice, we tend to use a stock index, such as the S&P 500, as a proxy for the market portfolio, and we estimate betas for stocks against the index.

The standard procedure for estimating betas is to regress stock returns (R_j) against market returns (R_m).

$$R_j = a + bR_m$$

where

a = Intercept from the regression

$$b = \text{Slope of the regression} = \frac{\text{Covariance }(R_j, R_m)}{\sigma^2_m}$$

The *slope* of the regression corresponds to the beta of the stock and measures the riskiness of the stock.

The *intercept* of the regression provides a simple measure of performance of the investment during the period of the regression, when returns are measured against the expected returns from the capital asset pricing model. To see why, consider the following rearrangement of the capital asset pricing model:

$$R_j = R_f + \beta\,(R_m - R_f)$$
$$= R_f\,(1 - \beta) + \beta\, R_m$$

Compare this formulation of the return on an investment to the return equation from the regression:

$$R_j = a + bR_m$$

Thus, a comparison of the intercept (a) to $R_f\,(1 - \beta)$ should provide a measure of the stock's performance, at least relative to the capital asset pricing model.[14] In summary, then:

[14] The regression is sometimes calculated using returns in excess of the riskless rate, for both the stock and the market. In that case, the intercept of the regression should be zero if the actual returns equal the expected returns from the CAPM, greater than zero if the stock does better than expected, and less than zero if it does worse than expected.

ANNEX 1

RABO BANK LETTER-1

Rabo India Finance
A 100% subsidiary of Rabobank International

Rabo

Rabo India Finance Limited
Office address GF / A-03 B, Ground Floor
Building No. 9, Tower A
DLF Cyber City, Phase III
Gurgaon 122 002, India
Telephone +91-124-271 3000
Fax +91-124-271 3005

Dated: June 10, 2008

To,

Yogesh Mehra
Managing Director
Enercon India Limited
Enercon Tower, Plot No. A-9,
CTS No. 700, Veera Industrial Estate,
Veera Desai Road, Next to Bhagwati House,
Andheri (West), Mumbai-400053

Dear Mr. Yogesh Mehra,

We wish to inform you that we are very concerned by the delay in CDM registration of your projects.

In particular, we would like to draw your attention to the Tungabhadra (22.8 MW) windfarm in Karnataka state which we financed in December 2006 and June 2007 in two disbursements, where the project is not performing at acceptable levels since the CER revenues you promised have not come through yet, in the absence of which debt servicing capacity of the windfarm is unacceptably low for us, since there is virtually no room left for even minor variations in wind availability before debt servicing from the windfarm's cash flows can begin to get impacted. We strongly feel that we may need to reassess your ability to service the debt from the project if the CDM registration is delayed any further. We request you to complete the remaining steps with respect to CDM registration promptly.

We hope you understand that as lenders we must ensure that the projects financed by us are viable and our lending in such projects is secure, before we extend financial assistance. For wind power projects, we expect, among other things, a minimum Debt Service Cover Ratio (DSCR) of at least 1.25 times, a Project IRR of at least 11-12% and an equity IRR of at least 15-16%, to satisfy ourselves that the project is economically viable, and that the owners will have an incentive to operate it over the period of the loan (and therefore also protect the interest of lenders). This expectation has been fairly constant over at least the last 5 years. Ratios like Debt Service Cover Ratio (DSCR), which are critical for us as lenders, tend to be unsatisfactory for us in the case of wind energy projects if they do not meet abovementioned minimum project or equity IRR levels. You would recall that for financing this project, CDM revenues were extremely important because your project was not able to meet the financing criteria without CDM revenues and as such, we would not have financed this project if CDM revenues were not expected.

We request you to give this matter your utmost priority.

Thanking you,

Yours sincerely

Jotdeep Singh
Director & Head
Renewable Energy & Carbon Credits
Rabo India Finance Ltd.
(100% subsidiary of Rabobank International)

Registered Office: GF / A-03 B, Ground Floor, Building No. 9, Tower A, DLF Cyber City, Phase III, Gurgaon 122 002, India.

ANNEX 2

RABO BANK LETTER-2

Rabo India Finance

A 100% subsidiary of Rabobank International

Rabo

Rabo India Finance Limited
Office address GF / A-03 B, Ground Floor
Building No. 9, Tower A
DLF Cyber City, Phase III
Gurgaon 122 002, India
Telephone +91-124-271 3000
Fax +91-124-271 3005

To

Mr. C Kumaraswamy
Manager-South Asia
Climate Change Services
Det Norske Veritas AS
Bangalore, India

Dear Mr. Kumaraswamy,

As a lender that frequently finances renewable energy projects in India, especially wind farms, we are able to certify that we, and, to the best of our knowledge, other lenders, do not consider that just because a project's Project IRR and / or Equity IRR is higher than interest rate, that it an adequate ground in itself to lend to a project, whether in renewable energy or other sectors. The reason for this is that lenders need an adequate buffer to provide a cushion for adverse developments (for example lower than expected power output). Further, a project IRR just marginally above interest rate neither provides an adequate DSCR (Debt Service Cover Ratio), nor any ability to prevent a loan going into default should interest rates rise, as in fact has happened in India from 2005 / 2006 to the present time, or project performance slip.

In our assessment therefore, not only does project IRR have to be higher than interest rate, but sufficiently higher to provide us with necessary cushion.

We hope this clarifies the matter.

Sincerely,

Oct 1, 2008

Jotdeep Singh
Director & Head - India & Regional Co-ordinator - Asia
Renewable Energy & Carbon Credits
Rabobank India Pvt. Ltd.
100% subsidiary of Rabobank

ANNEX 3

WACC CALCULATION

Weighted Average Cost of Capital:

WACC = [D/ (D+E)]*[Cost of Debt] + [E/ (D+E)]*[Cost of Equity]

Cost of Debt:

Cost of debt is defined as the rate at which lenders agree to lend money to a project. The additionality tool and the guidance to investment analysis clarify that for projects that benchmark for project with more than one potential developer should not be based on project specific parameters but should represent the standard in the market. Accordingly, the bank prime lending prevailing at the time of project start date has been considered as the cost of debt. The prime lending rate at the time of investment was in the range of 11.00% - 11.50% [Source Reserve Bank Web-link http://www.rbi.org.in/scripts/WSSView.aspx?Id=10693], the average PLR of 11.25% has been considered

Interest costs are tax deductible, therefore in order to arrive at the post tax cost of debt, the cost of debt is multiplied with marginal tax rate. The loan tenure of the project is 10 years, it may be noted that for the first 10 years, all power projects in India are required to pay tax @ 11.33% (as per section 80 IA of Income Tax Act). Accordingly the marginal tax rate has been considered as 11.33%

The post tax cost of debt therefore works out to: 11.25% * (1-11.33%) = 9.98%

Calculation of Cost of Equity:

The expected return on equity has been determined using the Capital Asset Pricing Model (CAPM)[1]. The CAPM economic model is used worldwide to determine the required/expected return on equity based on potential risk of an investment. The CAPM framework is the Nobel award winning work of financial economist Dr. William Sharpe.

Ke = Rf + B x (Rm - Rf)
where:
Ke = Rate of return on equity capital;
Rf = Risk-free rate of return;
B = Beta;
Rm – Rf = Market risk premium;

Risk free rate:

The risk free rate is understood as the rate of return on an asset that is theoretically free of any risks, therefore the rate of interest on government bonds are considered as risk free rates. Page 191 of text book

[1] The Capital Asset Pricing Model (CAPM) was published in 1964 by William Sharpe, for his work on CAPM Sharpe received the Nobel Prize in 1990. http://www.investopedia.com/articles/06/CAPM.asp

on "Corporate Finance Theory and Practice" by Dr. Aswath Damodaran[2] of Stern School of Business, New York University (attached as Appendix 5) describes that the long term government bond rates are suitable indicators of risk free rates since the time horizon for this investment is long term.

Accordingly the risk free rate has been taken from long dated Indian government bond rates at the project start date (which is January 2006) which has been considered as it was in the year of investment (i.e in that year, the company had the alternative of this long term risk free investment). The data on government bond rates is published by Reserve Bank of India. (Web-link: http://rbidocs.rbi.org.in/rdocs/Publications/PDFs/80303.pdf)

The applicable risk free rate is 7.34%.

Risk Premium:

The most common approach for estimating the risk premium is to base it on historical data, in the CAPM, the premium is estimated by looking at the difference between average return on stocks and average return on government securities over an extended period of history [page 190, Corporate Finance Theory and Practice, Dr. Aswath Damodaran. Attached as appendix 6]. It is preferred to use long term premimums, i.e over a period of 25 years, since considering shorter time periods can lead to large standard errors because volatility in stock returns [page 191, Corporate Finance Theory and Practice, Dr. Aswath Damodaran. Attached as appendix 7]. It is also preferred to calculate the risk premium based on geometric mean of the returns since arithmatic mean overstates the risk premium. Geometric mean is defined as the compounded annual return over the same period [page 191, Corporate Finance Theory and Practice, Dr. Aswath Damodaran. Attached as appendix 7].

Therefore the risk premium has been calculated as the difference in compounded annual return bewteen the BSE-Sensex and the Government bond rates since the year of inception of BSE Sensex, i.e. 1979 – 80. The detailed calculations are presented in the attached excel sheet.

Source: BSE Stock Exchange (www.bseindia.com)

The applicable risk premium is 9.12%.

Beta:

Beta (B) indicates the sensitivity of the company to market risk factors. For companies that are not publicly listed, the beta is determined by referring beta values of publicly listed companies that are engaged in similar types of business. The project activity type is wind power generation; the approach therefore should be to base the beta for the project on the beta values of listed wind power generation companies in India. However, there was only one wind energy or renewable energy power generation company (BF Utility) listed on any stock exchange in India (both BSE- Bombay Stock Exchange and NSE-National Stock Exchange) in year 2006[3]. Therefore, in the absence of adequate data on companies which are exclusively

[2] Dr. Damodaran is one of the foremost authorities in the world in the field of Investment Analysis

[3] This can be verified from the database available at the web-link www.securities.com (This website is owned by a Euromoney Institutional Investor Company and It delivers hard-to-get information on more than 80 emerging markets through its award-winning online Emerging Markets Information Service.)

into the exactly same type of business (i.e wind power projects), the next best option for assessing the risk of these projects is to consider the data available on companies which are involved in similar businesses.

Therefore, we have considered beta values of all electricity generating companies in India. The group of companies considered includes renewable as well as conventional power generating companies. Investors demand a higher return from renewable energy projects than from conventional energy ones, given the higher risks in renewable, including risks of technology, risks from significantly varying and unpredictable resource availability (e.g. wind), and a lower established support base for such projects relative to that for conventional power (e.g. grid connections, bank finance, suppliers, etc.). The use of this Beta value is therefore considered conservative, as it does not add for the higher risk of non conventional energy.

The applicable Beta value has been determined on the basis of the Beta values of all power generating companies in India which were listed on the stock exchange at the time of this investment. Beta values of individual companies have been sourced from Bloomberg and screenshots are available in appendix 3.

The table below summarises the beta values:

Bloomberg Symbol	**Company Name**	**Beta**
RELE IN Equity	RELIANCE ENERGY	1.02
GIP IN Equity	GUJARAT INDS	1.14
TPWR IN Equity	TATA POWER CO	1.32
NLC IN Equity	NEYVELI LIGNITE	1.15
CESC IN Equity	CESC LTD	1.71
BFUT IN Equity	BF Utility	2.37
		1.45

Source: Bloomberg[4]

WACC = [D/ (D+E)]*[Cost of Debt] + [E/ (D+E)]*[Cost of Equity]

For calculation of WACC, a debt : equity ratio of 70:30 has been considered, as typical for the project type[5].
WACC = 70%* 10.5% (1-11.33%) + 30%*(7.34% +1.45* 9.12%)
Therefore, WACC = 70% * 9.31% + 30% * 20.6% = **13.15%**

As explained under section B.5, sub-step 2(b), the actual cost of debt for the project is 8.5%, if the actual cost of debt is considered, the WACC works out to:

WACC = 70% * 8.5% (1-11.33%) % + 30% * (7.34% +1.45* 9.12%) = **11.45%**

---

4 The beta value used, are the regression betas calculated by Bloomberg based on periodic stock returns. Bloomberg also provides an adjusted beta value after making the following adjustments:
Adjusted Beta=Regression Beta (denoted as Raw beta) *(0.67) +1.00*(0.33)
Bloomberg states that this is a default adjustment on the assumption that in future, over a period of time all betas may tend towards the average beta i.e. one. The approach outlined in corporate finance states: the conventional approach to estimate the beta of an investment is a regression of return on investment against returns on a market index (please see attached page no. 196 from “Corporate Finance Theory and Practice by Aswath Damodaran as Annexure 8). Accordingly, the regression beta (and not the adjusted beta) value has been considered.

5 Several regulations and orders refer this as the normative debt equity ratio for wind power projects.

ANNEX 4

Clarifications provided for corrections requested question (Submitted on 8th February 2008)

KERC set a single electricity generation tariff that is applicable to all the wind power generation projects (including the Project Activity) in the Tariff Order dated 18 January 2005 "In the matter of Determination of Tariff in respect of Renewable Sources of Energy" *(source: http://www.kerc.org/english/index.html)*

Further, this tariff once fixed is applicable for all future wind power generation projects until a new tariff order replaces it.

In determining this tariff, as explained by KERC in the Tariff Order, it employs assumptions on the relevant parameters including capital cost, operating cost, plant load factor (or capacity utilisation factor), financing, taxation, etc. to arrive at the generation tariff that would cover the costs and provide the post-tax equity return. Thus, if a project is set up that has all the parameters exactly similar to those assumed by KERC in its Tariff Order, it will earn the benchmark post-tax equity return. However, if a project has parameters that are different than those assumed by KERC, its equity return will be different than the benchmark post-tax equity return and vice versa.

We provide an illustrative example of how this happens with the key parameter – capital cost per MW. As the tariff is established by KERC on a cost-plus basis, i.e., by relation to the capital cost, this is one of the key drivers of setting the tariff. During the public hearing process, various stakeholders suggested capital costs ranging from Rs. 42.5 million to Rs. 50.0 million and KERC chose Rs. 42.5 million as the reasonable capital cost to determine the tariff for all wind generation projects (refer to KERC Tariff Order).

However, the capital cost per MW of wind turbines in practice is far in excess of Rs. 42.5 million per MW. We provide examples below to show the capital cost per MW in Karnataka projects of different manufacturers and the proposed project activity.

UNFCCC Project ref. No	Title	Make	Cost per MW (Rs Million)
1082	7.85 bundled wind power project in Southern India	Suzlon	49.50
1308	3 MW wind power project at Chikasiddvanahalli, village Chitradurga district, Karnataka	NEG Micon	52.30
1259	Proposed project activity, Tungabhadra Wind Power Project in Karnataka	~~Enercon~~WWIL	50.00

The cost per MW value refers form the respective PDDs of the above-mentioned project uploaded at UNFCCC site.

In other words, if the project has parameters that are similar to the values assumed by KERC and a capital cost of Rs. 42.5 million per MW, using the tariff set by KERC, it would have earned the benchmark rate of return. It so happens that KERC has used extremely conservative assumptions in relation to the tariff parameters including the capital cost (without any provision of reviewing it to align it closer to the market) and therefore, the tariff set by KERC results in the Project Activity achieving equity IRR lower than the benchmark equity return.

ANNEX 5

TABLE OF COMPARISON BETWEEN KERC VALUES AND PROJECT VALUES

		Our Project	**KERC tariff guidelines**
Capital Cost per MW	Rs. Million	50 (purchase order)	42.50
PLF	%	26.50% (KERC)	26.50%
Insurance charges		0.18% (Insurance documents)	0%
O&M rate	% of project cost	1.25% (KERC)	1.25%
O&M escalation		5% (KERC)	5%
Debt %		70% (Loan Agreement)	70%
Equity %		30% (Actual)	30%
Interest rate		8.50% (Loan Agreement)	11%
Tenure	Years	10.00 (Loan agreement)	10.00
Depreciation rate		7.86% (standard practice)	7%
Interest on Working Capital		12% (conservative)	12.50%
Working Capital			
Receivables	No. of days	45.00 (conservative)	60.00
O&M expenses	No. of days	30.00 (conservative)	60.00
Equity IRR		**10.9 %**	**16%**

- - - - -

History of the document

Version	Date	Nature of revision
04.1	11 April 2012	Editorial revision to change version 02 line in history box from Annex 06 to Annex 06b.
04.0	EB 66 13 March 2012	Revision required to ensure consistency with the “Guidelines for completing the project design document form for CDM project activities” (EB 66, Annex 8).
03	EB 25, Annex 15 26 July 2006	
02	EB 14, Annex 06b 14 June 2004	
01	EB 05, Paragraph 12 03 August 2002	Initial adoption.
Decision Class: Regulatory **Document Type:** Form **Business Function:** Registration		