



BANNARI AMMAN SUGARS LIMITED

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Response to the "Request for Review"

UNFCCC Ref No. 1574

"20 MW Bagasse Based Co-generation Power Project at Bannari Amman Sugars Limited, Nanjangud, Karnataka"

21 May 2008
The CDM Executive Board
c/o UNFCCC Secretariat
Martin Luther King Strasse 8
D-53153 Bonn
Germany

Dear CDM Executive Board,

We are hereby submitting our responses to the requests for review of the "20 MW Bagasse Based Co-generation Power Project at Bannari Amman Sugars Limited, Nanjangud, Karnataka"; Project activity 1574. We are providing the necessary details to each of the queries as required by the Executive Board for registering the project activity.

Query 1:

Further clarification is required how the DOE has validated that the barriers presented to demonstrate the additionality of the project activity actually prevent the implementation of the project.

Response:

We identified two critical risk factors while evaluating the techno-commercial feasibility of the project activity:

- Technological risk – mainly underperformance, technology failure and equipment life
- Policy risk – uncertainty in the power purchase tariff

In the following, we have described in detail why the above two risks were of prohibitive nature to the implementation of the project activity in a business as usual scenario.

Technological risks:

We were mainly sceptical about the performance uncertainties with respect to efficiencies of major equipment, life, trouble-free plant operation and robustness of the technology. This apprehension was due to our unpleasant past experience with similar technology and its low prevalence in the region.

▪ ***Past experience with similar technology:***

Our past experience with a similar system (16 MW TG and 80 TPH boiler) installed at the project site was not pleasant; we faced persistent technical problems. Since commissioning (in March 2000), the system has been facing several recurring technical problems leading to shutdowns and significant revenue loss. The major problems faced are:

1. Scaling of Turbine internals
2. Load hunting
3. High gear box vibrations
4. Boiler tubes erosion
5. Furnace puffing

Out of the above problems scaling of turbine internals was more serious in nature. This was intimated to the equipment supplier, M/s BHEL, through our letter dated 28.11.2000 (Encl 1.a). BHEL after inspection informed us that the turbine steam flow path requires cleaning as the it got salted, through their letter dated 11.12.2000 (Encl 1.b). BHEL orally informed that this de-scaling activity can be completed within a week. Therefore, as we were not able to load the machine beyond 12 to 13 MW, it was decided to de-scale the turbine internals at the earliest. Accordingly the turbine was stopped and over haul work started on 18.01.2001 (Encl 1.c – Fax message of BHEL dated 25.01.2001). The over haul of TG, instead of one week, took nearly one month (**27 days – 10% of total working days**). Refer Encl 1.d – minutes of meeting made along with BHEL Commissioning Engineer. The turbine was re-commissioned on 11.02.2001 after completing the over haul.

The financial impact of this is as given below:

- Permitted power export to KPTCL from the TG= 13.25 MW
- Total power export lost due to shutdown = 13.25 MW x 24 Hrs x 27 days X 85% PLF = 7,298,000 kWh.
- Financial loss = 7,298,000 x INR 2.80 / kWh = INR 20.4 Million

The above problems left a negative impact about the technology on our Management. It was felt that the high pressure technology was not yet proven successfully.

Considering the technical problems encountered in the existing high pressure system¹, it is unlikely that our management would have opted to implement a similar system without a performance guarantee or contingency arrangement.

▪ **Low prevalence**

During the conceptualization of the project activity in the year 2002, the following similar high pressure cogeneration systems existed in the region:

S.No	Name	Starting Date	Remarks
1	Godawari Sugar Mills Ltd.	April 2002	Gets a higher purchase tariff as per MNES guidelines. Registered as a CDM project.
2	Shri Prabhulingeswara Sugar Works Ltd.	December 2000	Gets a higher purchase tariff as per MNES guidelines
3	Shamanur Sugars	August 1999	Gets a higher purchase tariff as per MNES guidelines
4	Bannari Amman Sugars Limited, Nanjangud	March 2000	Gets a higher purchase tariff as per MNES guidelines

The above data is based on the below survey;

- The list of grid connected sugar cogeneration systems in Karnataka existing at the time of conceptualization were identified from Karnataka Renewable Energy Development Limited (KREDL) website (Encl 1.e – KREDL website)
- Primary data collection from all these plants were done to identify the configuration details of these plants (Encl 1.f – Analysis of cogeneration systems in the region)

As indicated above, only 3 out of 46 sugar mills in the region had implemented the high pressure technology apart from us, all of which enjoy a higher purchase tariff² than the project activity. At such nascent stages of any new technology penetration and practical application, it is normal for

¹ Similar problems continue to persist in the system at presently also.

² Refer Encl 1.h – Proceedings of the Government of Karnataka, page 2, paragraph 1.

unexpected problems to surface, which would be corrected by the equipment supplier in the later systems by upgrading the design parameters.

As the operating pressure increases, even minor fluctuations in water/steam properties could cause dramatic effects on the performance and life of the boiler and TG. The equipment materials have to be designed to withstand the thermal stress expected as a result of high temperature and pressure differentials. A high pressure system is more sensitive to these factors than a low pressure system thus increasing the risk of performance loss and equipment damage.

Any performance loss or frequent maintenance shutdowns would correspondingly reduce the power and steam output. We were wary that such a situation would not only impact the energy sale revenue but also affect the primary manufacturing process.

This uncertainty in the performance of the high pressure system acted as a deterrent for us to opt for it, which was further emphasized by our unpleasant experience with similar technology.

Policy risks:

It may be noted that the sale of power to the state grid is the major source of revenue for the project activity. The return on investment from the project activity entirely depends on the power purchase tariff, any variation in which will directly impact the viability of the project activity. At the time of conceptualizing the project activity in the year 2002, the power purchase tariff being offered was as per the guidelines of the Ministry of Non-conventional Energy Sources (MNES), on the basis of which the commercial performance of the project was estimated by the project consultant (Encl 1.g – Extract from DPR on tariff assumed)³. However, the tariff for a project is considered final only when the Power Purchase Agreement (PPA) is signed, which happens only during the commissioning stage. Thus, any policy changes during the implementation stage would impact the project activity.

During the project conceptualization period, the Government of Karnataka was in the process of restructuring and rationalizing the power purchase policy. This may be noted from the proceedings of the Government of Karnataka (Encl 1.h – Refer page 2, paragraph 5) and its subsequent decisions. We were sceptical whether the MNES tariff would be offered to us at the time of commissioning the project activity. This uncertainty raised doubts on the long term viability of the project activity since the power purchase tariff is the most important economic

³ This MNES tariff is being provided to our 16 MW system commissioned in the year 2000

parameter of the project activity and any significant revision to it would make the project completely unviable.

Prohibitive nature of the risks:

As an established organization, though we tolerate certain risks while making investment decisions, they are generally limited to predictable external factors⁴ or controllable internal factors, the impacts of which are restricted to reduced profitability. However, technological and policy risks described above, that threaten the basic feasibility of the investment, are not entertained in the business as usual scenario unless contingency arrangements like insurance is available. For this project activity, the prospect of CDM revenues was considered right from the initial stages and was looked upon as a contingency arrangement that could offset the likely negative impacts from the risks perceived. In the absence of such a contingency arrangement, it is highly unlikely that we would have implemented this project activity against such critical risk factors.

Materialization of the risks:

It may be noted that our apprehensions have unfortunately materialized for our project activity, in the form of persistent technical problems and reduced power purchase tariff.

▪ ***Persistent technical problems***

Since commissioning, the TG has been facing steam leakage problem leading to frequent shutdowns and load limitations resulting in significant revenue losses.

Details of technical problems faced by the project TG is as follows:

S.No	Date	Nature of problem	Remarks
1	24.08.2004	Steam leakage from TG observed. The equipment supplier BHEL's personnel inspected the system.	Minutes of Meeting (MoM) with BHEL dated 24.08.2004 (Encl 1.i)
2	03.10.2004 to 27.10.2004	Steam leakage from TG casing rectification work – 1 st attempt <i>Shutdown for 24 days</i>	MoM with BHEL dated 02.11.2004 (Encl 1.j)
3	09.12.2004	Steam leakage from TG observed again	Letter No - BAS / K / BHEL / 383 / 2004

⁴ Such as fuel availability which is based on cane yield

4	10.03.2005 to 12.04.2005	BHEL Engineers attended the Turbine steam leakage problem – 2 nd attempt Shutdown for 30 days	MoM dated 13.04.2005 (Encl 1.k)
5	05.09.2005	Fire accident due to oil leakage	Lr. No. BAS/K/CO-GEN/ 9231 /05
6	27.12.2005	Steam leakage observed again. Information given to BHEL.	Lr. No. BAS/K/CO-GEN/ 9337 /05
7	28.01.2006	Bearing vibration problem started	Lr. No. BAS/K/CO-GEN/ 9365 /06
8	04.02.2006	Informed our apprehension to BHEL that the oil leakage appears to be serious in nature. This may result in any major fire accident again. Requested BHEL to depute their Engineer to site to take note of the condition and to advice us.	Lr. No. BAS/K/CO-GEN/ 9372 /06
9	18.02.2006	Engineer from BHEL visited our site and advised us to carryout the spectrum analysis.	MoM with BHEL
10	05.06.06 to 07.07.06	BHEL Engineers attended the Turbine problems again - 3 rd attempt	MoM dated 15.07.2006 (Encl 1.1)
Note: The above table provides only a summary and is not exhaustive. Additional information may be furnished if required			

It may be noted from the above that since commissioning, the project TG has been facing recurring problems resulting in frequent shutdowns, loading limitations and maintenance expenditures.

▪ ***Reduced tariff***

As a result of tariff restructuring, the state electricity board reduced the tariff for the project activity to INR 2.80 per kWh (Encl 1.m – Extract from PPA), 20% lower than the envisaged tariff of INR 3.49⁵ per kWh, as per MNES guidelines, prevailing during the conceptualization of the project activity.

We would like to reinstate that the project activity has been implemented, notwithstanding the critical risk factors, considering that the CDM revenue would supplement the revenue and help in its sustained operation.

⁵ Based on INR 2.25 per kWh for base year 1994-95 and 5% escalation thereafter, works out to INR 3.49 per kWh for year 2003-04

Query 2:

Further clarification is required to demonstrate the prior consideration of the CDM before the start date of the project activity, particularly in context of: a) delay to initiate validation by 4 years and eight months after the start date of the project and b) the methodology AM0006 v1 was approved on 30 September 2005, after the start date of project and the commercial operations.

Response:

Consideration of CDM:

- During December 2000, we had the opportunity to gain knowledge about the carbon trading concept during a seminar on “Business opportunities in Bagasse based Cogeneration” organized by the Confederation of Indian Industries (CII), USAID⁶ and WII⁷. The contact person for this project activity (Mr.R. Murugesan) attended the seminar and has been spearheading the CDM process (Encl 2.a - Seminar invitation and delegate pass indicating name of person)
- The concept of CDM and its benefits was also elaborated by our power plant engineering consultant during the project feasibility assessment. The same is reflected in their Detailed Project Report (DPR) prepared in May 2002 (Encl 2.b – Extracts from the DPR)
- Our Board of Directors, in their meeting on the 24th June 2002, took into account the benefits of CDM while deciding on the project implementation. Copy of the Board Meeting Minutes book is being submitted (Encl 2.c).

Starting date of the project activity:

- The Letter of Intent (LoI) for the purchase of the project equipments was placed on 14 September 2002 and subsequently the Purchase Order (PO) was placed on 30 May 2003. Since the decision to implement and real action started with the issuance of LoI, the same is considered as the starting date for the project activity.

⁶ United States Agency for International Development

⁷ Winrock International India

Commencement of the CDM process:

The CDM process was initiated by us immediately upon starting the project activity without any delay. This is justified by the following facts:

- The CDM consultant was appointed by us on 21 March 2003 (Refer Encl 2.d – Copy of work order and bank cheque for advance fee payment). This is before the date of purchase order of the project equipments.
- The DOE for validation was appointed on 06 December 2003 (Refer Encl 2.e – Letter from DOE on receipt of work order).
- The Project Design Document (PDD) was prepared and the application for obtaining the Host Country Approval (HCA) was submitted to the Designated National Authority (DNA) in January 2004.
- The meeting with the DNA took place on 31 March 2004 and subsequently the HCA was received on 11 May 2004⁸ (Encl 2.f - HCA).

Delay in commencement of Validation process:

Though the PDD was prepared and submitted to the DNA in January 2004 and a DOE was appointed in December 2003, the Validation could not be commenced immediately due to the following facts:

- A suitable approved CDM methodology was not available.
- In September 2003, our CDM consultants submitted a new methodology for grid connected renewable energy projects, NM0030, though for a different project activity⁹ worked by them. We awaited the approval of this methodology for completing the PDD and commencing the Validation process.
- In September 2004, the Meth Panel recommended not to approve NM0030-rev. Though AM0015 was approved at the same time, it could not be applied to our project due to constraints in applicability conditions¹⁰. Subsequently, we awaited the approval of a similar methodology, NM0050, submitted in April 2004 for another project activity, which was in consideration by the Meth Panel.

⁸ Please note that a revised HCA was issued later (on 28 Feb 2005) as per the DNA's new format, which is uploaded by the DOE with the registration request.

⁹ NM0030 was submitted for the bagasse co-generation project activity implemented by Balrampur Chinni Mills Limited, which was also worked by our CDM consultant.

¹⁰ AM0015 stated that the plant should use only bagasse generated in-house. However, the project activity may have to run on purchased biomass residues or fossil fuels during emergencies like drought.

- Though this methodology got approved as ACM0006 V1 in September 2005, it was applicable only to projects with back-pressure turbines. Once ACM0006 V2 was approved in March 2006, the PDD was submitted for Validation and web-hosted in April 2006¹¹, 3 years and 6 months after the starting date.
- However, on account of delays during the validation process, the validation was reassigned to a DOE with more experience in the sector (at that point in time). The project was web-hosted again in June 2007¹² applying ACM0006 V4.

It may be clear from the above facts that we have taken into account the CDM while deciding to implement the project activity. Further, we initiated the CDM process immediately after starting the project activity, by appointing the CDM consultant and subsequently the DOE for Validation. However methodological and procedural issues have resulted in the delay of our CDM process.

¹¹ <http://cdm.unfccc.int/Projects/Validation/DB/VVEZ3K7B2YZCLIP7TJUR4MB2O6GJWX/view.html>

¹² <http://cdm.unfccc.int/Projects/Validation/DB/BM7LIROCMQ5KSEGLIJBTU23DB7Y8YK/view.html>

Query 3:

The DOE should clarify how it has validated that the project activity complies with the requirement of scenario 16 of ACM0006 v4 as: a) the bagasse is assumed to be left to decay without use despite having a sale value, and b) the scenario requires that the existing units continue to operate in the same manner after installation of the new power unit.

Response:

Bagasse would be left to decay:

Please note that the project activity is located in a remote area. In the area surrounding the project site, there is surplus availability of biomass residues. During Validation, information was obtained from the state nodal agency for renewable energy, Karnataka Renewable Energy Development Limited (KREDL), on the surplus availability of biomass residues in the region (Encl 3.a – Letter from KREDL) covering two districts. As indicated by KREDL, following is the availability of biomass in the region:

Parameter	Quantity	Remarks
Surplus availability in Mysore district	295680 Tonnes	KREDL data (Encl 3.a)
Surplus availability in Chamraj Nagar district	19880 Tonnes	KREDL data (Encl 3.a)
Total surplus biomass available in the region	315560 Tonnes	KREDL data (Encl 3.a)
Proposed capacity of biomass power plants in the region	19.5 MW	KREDL data (Encl 3.a)
Specific Fuel Consumption (SFC) for biomass power plants	1.16 Tonnes / MWh	Page 29 of KERC tariff order (Encl 3.b)
Biomass required for 19.5 MW power plants	198152 Tonnes	Based on above SFC and 100% PLF
Surplus available after meeting demand of power plants	117409 Tonnes	40% is surplus

It may be noted that apart from the maximum consumption for 19.5 MW biomass power plants, there is 40% surplus biomass availability in the region which is left to decay or burnt without use.

Further, independent biomass power producers would not prefer to use bagasse as the fuel owing to the high moisture content and lower calorific value compared to other biomass residues. Also, cost of transportation and storage area requirement is higher due to high moisture content. Unless specifically designed for bagasse, the normal boilers would encounter problems with performance and maintenance. Considering all the above factors, it is unlikely that our surplus bagasse would be sought by these power producers, and therefore would be left to decay as it is of no sale value.

Existing units:

The following table provides details of the cogeneration configurations at the project site in different scenarios:

Equipments	Pre-project	Baseline	Project
7.5 MW 45 ATA system (2 Nos. 32 TPH boilers and 3 Nos. 2.5 MW TGs)	Yes	No	No
16 MW 67 ATA system (80 TPH boiler and 16 MW TG)	Yes	Yes	Yes
20 MW 67 ATA system (120 TPH boiler and 20 MW TG - project activity)	No	No	Yes

- The 45 ATA system was installed in the year 1992-93 along with the Greenfield sugar plant capacity of 2500 Tonnes Cane per Day (TCD).
- During the year 1998, the 16 MW 67 ATA high pressure system was planned to be installed along with the sugar plant capacity expansion to 5000 TCD. The 16 MW 67 ATA system was installed with a view to improve the efficiency of electricity generation by replacing the 45 ATA low pressure system and to utilize the surplus bagasse from the sugar plant capacity expansion. This was verified by the DOE from the Detailed Project Report of the 16 MW system dated May 1998.
- The 45 ATA system was not retired immediately after the installation of the 16 MW system. The system was to be retained until the operations of the 16 MW 67 ATA system are stabilized and the site personnel become experienced with its complicated operational procedures. This was a precautionary measure so that even if the 16 MW system is unable to operate, the sugar plant can be run with the 45 ATA system.

- As described above in our response to Query 1 under “Technological risks”, the 16 MW system faced several technical problems and shutdowns which necessitated the continued operation of the 45 ATA system. However, the operations of the 16 MW system got stabilized in the year 2003 and subsequently the 45 ATA system was dismantled in year 2004. For logistical ease and to reduce the downtime, the retirement of the 45 ATA system was scheduled at the time of commissioning the 20 MW project activity.
- It may be noted from the above that the 7.5 MW system would have been anyways retired in the absence of the project activity and therefore is not a part of the baseline scenario. In the baseline scenario, only the 16 MW system would be present, which continues to operate in the project scenario.
- Further, as a conservative method and inline with the requirement of scenario 16, the historic electricity generation from the 7.5 MW system has also been included in the parameter “EG_{historic, 3yr}”, which is deducted from the project energy generation to arrive at “EGy – Incremental electricity generation from the project activity”.

In view of the above, it may be concluded that the project activity meets the applicability of scenario 16 both in terms of a) bagasse is left to decay and b) existing units continue to operate and results in a conservative calculation of emission reductions.

We would be glad to provide any further clarifications on this important matter.

Yours truly,

For Bannari Amman Sugars Limited


(R. Murugesan)

Authorized Signatory