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

CONTENTS

Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

Natural Gas based grid connected power project at Peddapuram, A.P. by Gautami Power Limited
Version: 064~~3.1~~
Date: 07~~22~~/09~~8~~/20133~~1~~

A.2. Description of the project activity:

The proposed project activity is commissioning and operation of a new, green field 469 MW Natural Gas fired, gas turbine based combined cycle power plant. The proposed project activity is being installed by GVK Gautami Power Ltd. (GPL)[1] at Industrial Development Area, Peddapuram, near Samalkot in East Godavari district, Andhra Pradesh, India. The project activity uses relatively cleaner fuel, natural gas instead of most common fuel in the grid i.e. coal for power generation. Thus, the project activity will avoid significant emission compared to the usual practice in coal dominated Indian power sector.

Purpose of the project activity:
The purpose of the project activity is commissioning and operation of 469 MW natural gas fired power plant. The project activity will be less emission intensive compared with the common coal based power and average fuel mix in the grid. Thus, the project activity aims at reducing the GHG emission reduction by use of a relatively lesser GHG intensive fuel i.e. natural gas.

This being a green field project activity, the pre-project scenario would be electricity generation using the current fuel mix in the grid.

Project planning history: A power plant (where the project activity exists) was taken up for development by Satyam Constructions Ltd. in 1995 (300 MW liquid fuel based) and PPA was signed in 1997 with APSEB. Another 227 MW liquid fuel based power plant envisaged by Nagarjuna Construction Co. Ltd. also signed PPA in same time. In 2000, Government of Andhra Pradesh decided to convert all short gestation period power plants to be natural gas[2] based and approached for gas supply to these plants. These two plants (and holding companies Gautami Power Private Limited and NCC Power Corporation Ltd. were merged by the High Court order in 2001 and the later company ceased to exist[3]). The PPA for 464 MW CCPP using NG was approved by APERC on 12/04/2003. This is the major requirement (approved PPA) to apply for loans and to envisage setting up the power plant. All other earlier milestones are feasibility studies and due diligence/ approval processes. Thus, any of these can not be taken as the investment decisions as before achieving financial closure, the project plant can not come up.

Technical description of the project activity:

---

[1] GVK Gautami Power Ltd. is the new name of PP as per order dt. 08/09/2009 (letter from 'Registrar of Companies, Andhra Pradesh' submitted to DOE)

[2] PPA of Gautami Power Ltd. dt. 18/06/2003 pg. 4, Clause 15 - '… the GOAP decided to convert the other Short Gestation Power Project to operate on Natural Gas only instead of Naphtha … '

[3] PPA of Gautami Power Ltd. dt. 18/06/2003 – Clause 22, pg. 6 '…. and NCC Power Corporation (P) Ltd., will cease to exist with effect from 15.3.2001'

The power generation components of the project activity comprise of two gas turbine generators (GTG), two heat recovery steam generators (HRSG) and one steam turbine generator (STG). The combustion turbine module consists of a 21-stage compressor and 5-stage turbine. The turbine unit has annular type combustors. The combustion of air fuel mixture takes pace in the combustors. The accessory module is mounted on a separate base frame and houses the mechanical and the control elements required for the combustion turbine operation. The major components located in the auxiliary block are lubricating oil system with lube oil reservoirs and lube oil coolers. The combustion turbine is started by operating the generator as a variable speed motor. The variable frequency power required for this purpose is generated by the static frequency converter system from station auxiliary power systems (only during start up). This electricity usage is accounted in the total auxiliary consumption for calculation of net export. The combustion turbine is a single shaft machine with the compressor and turbine installed in a single casing.

The heat recovery steam generator (HRSG) is a triple pressure, unfired, horizontal gas flow type with internal thermal insulation, platforms and ladders. Feed water and steam sampling arrangements are provided as required. The water circulation through the evaporator is by means of natural circulation set up by thermo symphonic action. Steam from HRSG is supplied to a condensing type non-reheat steam turbine through steam piping.

The steam turbine generator (STG) is triple pressure condensing type. The steam entry to the turbine is through the emergency stop and control valves, which govern the speed/ load on the machine. The turbine control system is electro-hydraulic type. The STG is complete with lube oil and control oil system, governing system, protection system and gland sealing steam system. The turbine is provided with low speed barring gear, which rotates the coupled shaft. The turbine is also provided with a rotor jacking oil system. The steam turbine has a condenser for condensing the exhaust steam from the steam turbine.

The generators (210 MVA) are coupled to gas turbines and steam turbine. They deliver the power at 15.75 kV with 0.8 PF; 3 phase; 50 Hz at site ambient conditions of 29ºC and a relative humidity of 70%. In absence of the project activity, this electricity would have been generated with the current fuel mix in the carbon intensive grid. As derived in the Section B.4, the project proponent could have opted for a coal based power plant, which is used as a baseline for the project activity emission reduction calculations here. CO_2 is considered as the major emission source in both the baseline and project activity. Leakage and project activity emissions are due to fugitive emissions from extraction to distribution of NG.

How the project activity reduces greenhouse gas emissions

In the absence of the project activity the project proponent would have opted for a coal based power plant as described in the section B.4. The project activity would thus reduce anthropogenic GHG emissions into the atmosphere by the use of relatively lower GHG intensive fuel (Natural Gas) and much higher efficient power generation in comparison to coal.

Contribution of the project activity to sustainable development

Ministry of Environment and Forests, Govt. of India has stipulated the social well being, economic well being, environmental well being and technological well being as the four indicators for sustainable development in the interim approval guidelines host country approval eligibility criteria for Clean Development Mechanism (CDM) projects[4].

[4] http://cdmindia.nic.in/host_approval_criteria.htm

Social well-being:

- Industry – the proposed project is with an investment of ₹ 14.5 billion and will have a significant positive impact on the industrial growth in the region as well as in the country
- Infrastructure – the region around the proposed project site does not have very good infrastructural facilities. Near the project site, the facilities for public transport, water supply, telecommunication, education, public health etc. are inadequate. With the setting up of major industry like this, the region will naturally help directly and indirectly in the development of civil infrastructure
- Employment – the proposed project activity has provided direct employment to about 525 persons during the construction and 140 during the normal operation. In addition it is expected that up to 30 persons will be directly benefited through casual work, subcontracts, trading etc.
- The PP has also committed to utilize 2% of the CDM revenue towards socio-economic development (as per the plan given to NCDMA)[5].

Environmental well being:

- The electricity generated by project activity will be supplied to Southern grid, which otherwise would have been generated by fossil fuels. Hence, the project activity will help in reduction of the greenhouse gases emission and other air pollutants (especially NOx and SO_2)
- The project activity helps in conservation of coal which at present are predominantly used for power generation

Economic well being

- This project will demonstrate the use of new financial mechanism (CDM) in raising finance for power generation from relatively cleaner fuel in coal dominated economy

Technological well being

- The project uses the best available technology in the form of combined cycle
- The space requirement per MW capacity is lower compared to the conventional coal fired power plants

Thus the project activity meets the National Sustainable Development criteria and the Host Country Approval is awarded to the project activity on 06/02/2009.

A.3. Project participants:

Name of the party involved ((Host) indicates Host party)	Private and/or public entity(ies) project participants (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
India (host)	GVK Gautami Power Limited, Hyderabad (Private entity)	No

The GVK Gautami Power Limited, Hyderabad is the sole owner of the project and the CERs generated. The company is listed on stock exchange/s and has some public shareholding.

[5] Refer Annex 4 for a brief monitorable action plan

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

India

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

Andhra Pradesh

A.4.1.3. City/Town/Community etc:

Industrial Development Area, Samalkot, East Godavari District

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

The 469 MW combined cycle power plant is located at Industrial Development Area, Samalkot, near the port town Kakinada, Andhra Pradesh. The site is 15 km from the sea port at Kakinada and 3 km from the Samalkot railway station. The geographical coordinates of the Samalkot are 17º03'03" N and 82º07'04" E.

(Source: www.mapsofindia.com)

Figure 1: Location of the project activity [marked as ■] (a) in India (b) in West Godavari District

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

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

The project activity is construction and operation of a new natural gas fired grid-connected electricity generation using combined cycle power plant. As per the scopes of the project activity listed in the "List of Sectoral scopes" (Document CDM-ACCR-06 Version 04)', the project activity will fall in Scope Number 1, Sectoral scope – Energy industries (renewable - / non-renewable sources) being a Grid-connected electricity generating project using non-renewable fuel in energy industries.

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

The project activity is construction and operation of a new natural gas fired grid-connected electricity generation using combined cycle power plant.

The scenario existing prior to the start of the implementation of the project activity:
This being a green field project activity, the pre-project scenario would be electricity generation using the current fuel mix in the grid.

Project Activity:
A new 469 MW natural gas based combined cycle power plant is installed under the project activity. The proposed project activity was executed under the Engineering, Procurement and Construction (EPC) contracts basis to achieve the project commissioning within the normal period stipulated under the typical PPA. The EPC contract was awarded to Alstom (Switzerland) Ltd. and Alstom Projects India Limited. The Operation and Maintenance of the project is proposed to be carried out by GVK Power & Infrastructure Limited, a GVK group company. A long term spares supply agreement for the gas turbines is entered with Alstom to cover certain operational risks.

Alstom Limited, a multinational company, possessing the broadest scope of power generation systems, equipment and services in the industry. Alstom's gas turbine range covers a wide spectrum of products, including machines for both the 50 Hz and 60 Hz markets. The gas turbines are characterized by cost efficiency, high availability and reliability and fuel flexibility. These units operate in a combined cycle mode of operation. They can be fuelled by natural gas, light oil, crude oil or coal gas. A special switching facility eliminates dependency on any one fuel.

The main equipments are as follows
- Gas Turbine Generator
- Heat Recovery steam Generator (HRSG)
- Steam Turbine Generator (STG)

The details of the equipments are summarized in the table below.

S.N.	Equipment	Specifications
1	Gas turbine (GT)	Two (2) nos. Alstom Power make (Type - GT13E2) heavy duty industrial gas turbines equipped with the lean premix dry low NOx EV burners; holds 21-stages compressor and 5-stage turbine blades;

		Capacity- 2 x 152.438 MW at site conditions of 29 deg C, 70% RH and 50Hz frequency
2	Heat recovery steam generators (HRSG)	Make -ALSTOM Power, Triple Pressure Capacity: HP/ IP/ LP Flow: 56.95/ 11.1/ 9.7 kg/s Temp: 508.3/ 506/ 151.2 deg C Pressure: 96.35/ 24.6/ 4.8 bar
3	Steam turbine generator (STG)	ALSTOM Power, Triple Pressure Capacity- 164.235MW at site conditions of 29 deg C, 70% RH and 50Hz frequency

The power generated at 15.75 kV is stepped-up to 400kV through step-up transformers. The step-up transformers are connected to project switchyard by overhead transmission lines. The 400kV project switchyard is connected to APTRANSCO's 400kV sub-station.

The project activity has an expected life time of 15 years[6]. The heat rate of the plant would be 1850 kcal/kWh on GCV (or 1682 kcal/kWh on NCV). The power plant will deliver annual 3387 GWh exportable electricity and consume 1.88 million SCCM natural gas per day. The gas supply agreement with the Gas Authority of India Ltd. (GAIL) is signed for supply of 1.96 million SCCM gas. ~~The monitoring for the project activity constitutes the electricity exported, quantity of natural gas consumed and its NCV. The electricity exported in measure at the project switchyard dispatch station by two separate meters (main and check). The quantity of gas is monitored at the gas suppliers terminal at the project site and also checked before the usage at GT. The supplier terminal also measures continuous NCV of the gas being fed.~~

Presently RIL (and its partners) is the gas supplier and uses GAIL's gas conditioning skid in the project boundary. Only GAIL does NG quantity and calorific value (CV) metering near the project activity plant. The gas supplier – RIL does not have monitoring (gas flow, CV) station near the project boundary. Thus, monitoring plan of the project activity will treat GAIL meter readings and invoice equivalent to the "suppliers' invoices" (as monitoring methodology requires supplier data to be used). In future if gas supplier and/or transporters are changed, the nearest fuel metering point near the project plant (belonging to either gas supplier or transporter) will be used for monitoring. The quantity of gas is monitored at the GAIL terminal at the project site. The GAIL's terminal also measures continuous CV of the gas being fed. There are two gas supply lines at GAIL's skid (Loop-A and Loop-B and each is having Gas flow meter (owned and maintained by GAIL)). These two lines merge when it comes to PP's boundary. PP does cross check of gas consumed using inbuilt metering mechanism in the gas turbines.

The project activity uses a comparatively lesser GHG intensive fuel than the common coal based power plants and reduced the average emission per unit electricity generated in the grid. The project activity is a green field project, so nothing existed at the project site in the pre-project scenario. The equivalent electricity would have been generated in the grid using current fuel mix in the absence of the project activity.

The technology for the power generation is best available in the category. The choice of the technology will further reduce the GHG emission associated with the most probable alternative choice – coal fired thermal power plant and open cycle option. In addition, the emissions of CO, particulates (fly ash) will

[6] http://mnes.nic.in/baselinepdfs/annexure2c.pdf

also be reduced compared to the identified alternate. The project activity will abide by all the regulatory norms of the pollution control board and will maintain environmentally clean and sound process.

No technology transfer is involved in the project activity from Annex I countries.

Under the EPC contract, all the major units were imported from Alstom Europe for the project activity. The initial training of the employees for the operation and maintenance has taken place as part of the EPC. The training was on the project activity site as well as the EPC contractor's European offices.

The project technology was the best available at the time of EPC. It includes advanced features like dry low NOx EV burners for reducing the emissions of NOx (http://www.power.alstom.com/home/equipment___systems/turbines/gas_turbines/gt13e2). The project proponents will not replace the units in the project activity more efficient technology within the project period.

The baseline is identified by analyzing various options that deliver similar output and services. The alternatives discussed include 469 MW proposed project activity not taken as CDM project, gas based open cycle power plant, gas plant in the cogen mode, Power generation using coal as the energy source, Power plant using coal as fuel, hydro electric power plant (reservoir and/or run-off-the-river), wind power, cluster of Diesel Engine based power plants, nuclear power plant, electricity imports from other grids and coal fired super critical power plant.

In absence of the project activity, as identified in the section B4, the project proponent could have chosen a coal fired power plant of similar power output resulting in substantially higher GHG emissions. Thus, the southern grid would have continued to generate the electricity generated by the project activity using existing carbon intensive fuel mix. The GHG emission sources considered in the baseline and the project activity are CO_2 due to fuel combustion and leakage in the project scenario due to the extraction to distribution of natural gas. The net GHG emission reduction is calculated in a conservative manner after taking into account all the emission in the project activity.

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

Years	**Annual estimation of emission reductions in tonnes of CO_2e**
2011	1,293,422
2012	1,293,422
2013	1,293,422
2014	1,293,422
2015	1,293,422
2016	1,293,422
2017	1,293,422
2018	1,293,422
2019	1,293,422
2020	1,293,422
Total estimated reductions (tonnes of CO_2e)	**12,934,200**
Total number of crediting years	**10**
Annual average over the crediting period of	**1,293,422**

estimated reductions (tonnes of CO_2e)	

A.4.5. Public funding of the project activity:

Public funding from Annex 1 countries and diversion of official development assistance (ODA) is not involved in this project. The details of the project cost and means of finance are presented below.

SECTION B. Application of a baseline and monitoring methodology

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

Title: "**Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas**"
Reference: Approved baseline methodology AM0029
Version 03,
Sectoral Scope: 01,
EB 39

Title: "Tool for the demonstration and assessment of additionality"
Version 05.2
EB 39

Title: "Tool to calculate emission factor for an electricity system"
Version 02.1
EB 50

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

The project activity is construction and operation of a new, green field natural gas based power plant for supply to the grid. The table below compares the applicability conditions of the AM0029 and the project activity scenario to justify the use of this methodology.

S. No.	Applicability condition of AM0029	Project activity condition	Remark
1	The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant	The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant. Natural gas is the only fuel of the project activity and no other fuel will be used as start up or in co-firing.	The applicability condition is met
2	The geographical/ physical boundaries of the baseline grid can be clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available	The physical boundaries of the baseline grid i.e. southern grid are clearly identified and its information is publicly available from Central Electricity Authority, Government of India	The applicability condition is met

3	Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity	Natural gas is abundantly available in region and country, as will be shown in following section. Also, the future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity	The applicability condition is met

Abundance of natural gas in India and the region of the project activity:

The spirit of emphasizing "sufficient availability" of NG in the methodology as an applicability criterion is:

(a) to ensure that NG from other users are not diverted and
(b) to ensure future power generation facilities of comparable size are not deprived due to NG being taken up by the project activity [Ref: footnote No. 2 of the AM0029, Version 3]

The points (a) and (b) above are borne out by the clarification [Ref: F-CDM-AM-Clar_Resp_ver 01.1 - AM_CLA_0091] issued by EB in response to a DOE query. In the response, EB also clearly mentions how the applicability condition pertaining to availability is to be implemented. In EB's view, a project activity to demonstrate that it meets the applicability condition will need to do so by resorting to appropriate monitoring. The relevant excerpt from EB's clarification– "*the monitoring should show that satisfying the project activity's demand for natural gas will not lead to shortages in supplies of the gas to other projects within the country*".

In other similar examples, recently registered projects from China in the applicable methodology AM0029, have shown 'LNG import agreements from other countries like Malaysia' (Project reference No.s 1381, 1343, 1344) in support of the NG availability. Thus, NG availability in the project activity region alone is not the applicability of methodology here. The same spirit of applicability allows new power plant even with imported NG to qualify for AM0029.
In this project we demonstrate that:

1) NG was sufficiently available in the source of supply so that other NG based projects do not get deprived and leakage does not occur.
2) Also future natural gas based power capacity addition also not constrained

The applicability condition in the methodology aims to avoid the diversion of natural gas from other future and existing users. It is evident from the AM0029 applicability condition on sufficient availability 'future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity'.

India has about 0.4% of world's natural gas reserves[7]. However, India continued to be one of the least explored regions with 30% of its estimated gas reserves explored so far. Almost 70% of India's natural gas reserves are found in the Bombay High basin and the state of Gujarat[8]. Off shore reserves are also

[7] http://www.nedcap.org/index_files/Page2514.htm

[8] http://iea.org/textbase/papers/2000/oilgas.pdf

located in Andhra Pradesh coast (Krishna Godavari Basin) and Tamil Nadu coast (Cauvery Basin)[9]. Onshore reserves are located in Gujarat and the North Eastern states. Smaller reserves are also found in Rajasthan[10].

At the time of initiation of the project activity i.e. award of the EPC Contract (27/09/2003), Natural gas was available for procurement and there have been no evident restrictions caused by the project activity's choice of natural gas as the fuel, on significant future capacity additions to the baseline grid comparable in size to the project activity, in choosing natural gas as fuel. Some of the examples of sufficient availability of natural gas in the market in Andhra Pradesh, in which state the project activity is located is explained in the following paragraphs. The following table indicates the geographical distribution of the Natural Gas in India.

Geographical distribution of gas production in India (figures in MCM)		
State	**2001-02**	**2000-01**
Onshore		
Arunachal Pradesh	32	32
Assam/Nagaland	1992	2204
Gujarat	3280	3149
Andhra Pradesh	1797	1604
Tripura	416	376
Tamil Nadu	349	200
Rajasthan	101	160
Total	7967	7725
Offshore*		
ONGC	18317	18465
Private/Joint venture company	3430	3287
Grand Total	29714	29477
* Majority production from fields based in Western Off shore		

(***Source*** : http://petroleum.nic.in/petstat.pdf)

Table below provides the gas production in the state during 2000-2005.

Natural gas production-Andhra Pradesh vis-à-vis India (in MCM)			
Year	**Andhra Pradesh**	**India Total (Onshore & Offshore)**	% of state in total production
2000-2001	1604	29477	5.44
2001-02	1797	29714	6.04
2002-03	2038	31389	6.49
2003-04	1927	31962	6.02

9 http://www.sourcewatch.org/index.php?title=India's_oil_industry

10 http://petroleum.nic.in/ng.htm

2004-05	1707	31763	5.37

(***Source***: http://petroleum.nic.in/petstat.pdf)

For the project activity, GPL has made agreements with M/s Gas Authority of India Limited (GAIL) for the gas supply quantity of 1.96 MCMD natural gas till 31/12/2010[11]. ~~As i~~It can be seen that, the project activity has agreement for utilizing annual 715.4 MCM (considering 1.96 MCMD for 365 days operation) of Natural Gas against the total production of 2038 MCM of Natural Gas in Andhra Pradesh in 2002-2003. This was only 35.1% of the Natural Gas production in the state of Andhra Pradesh for the year.

Apart from this, GPL has also entered into an agreement with Reliance industries limited, for which the Term sheet has been signed on 09/06/2007. The project proponent is now using the Natural gas supplied by Reliance Industries Limited. The agreement with RIL is for 70699 MMBtu which is equivalent to approximately 2.23 MCMD. This supply is assured till 31st March 2012 which can be extended further.

The following table also provides the Reserves (Balance Recoverable) potential of Natural Gas in India

Natural Gas Reserves	
Year	In BCM
2000	760
2002	751
2003	854
2004	923
2005	1101

(***Source***: http://petroleum.nic.in/petstat.pdf)

As it can be seen from the above table, the natural gas reserves are sufficiently available in the country and at the time of real action of the project activity the reserves were to the order of 751 Billion Cubic Meter (2002-2003) in comparison to the supply commitment by GAIL towards the project activity of 1.96 MCMD (which is equivalent to 715.4 MCM considering an operation of 365 days in an year). This means that the commitment of natural gas quantity to the project activity by GAIL is only 0.095% of the total reserves of natural gas during the period of 2002-2003 and the available reserves are capable of firing more than 1000 times the installed capacity of the project activity. The gas availability in the country after 3 years of the date of award of the EPC Contract (generally the time required to construct the infrastructure facility) of the project activity is 1101 BCM which is capable of firing more than 1500 times the installed capacity of the project activity.

In the state of Andhra Pradesh, the demand from consumers having firm commitments for supply in the year 2001-2002 was 6.12 MCMD. Against this demand, the availability from GAIL for the year 2001-2002 was 7.50 MCMD. Hence, it is without doubt that this project activity will not constrain future natural gas based power capacity additions, comparable in size to the project activity.

The following paragraphs also elaborate on the sufficient supply of the natural gas vis-à-vis demand projection of the use of the Natural Gas in the state of Andhra Pradesh.

[11] Gas Supply Contract with GAIL; page 5

The "price inelastic" supply constraints can occur mainly in the cases where there is no possibility of expansion of Natural Gas reserves or the demand projection of Natural Gas is more than the supply projection of Natural Gas in the region. The following paragraphs elaborate on the demand supply positions and also the future capacity expansions of the Natural Gas reserves in the state of Andhra Pradesh.

Demand Projection of Natural Gas:

The report of the Sub-Group on Natural Gas availability for the Tenth Plan (2002-2007) has undertaken the study of gas market in India. The report compiles a number of studies available for projections of gas demand build up (***Source***:http://www.infraline.com/ong/default.asp?URL1=/ong/naturalgas/SubGroupReport_NGA02-07(i).asp&idCategory=4807).

Further, there are gas demand estimates following out of (i) gas committed supply already made by GLC (ii) requirement of gas by existing users, presently using liquid fuels/ feedstock. The sectors driving the gas demand are Power sector and Fertilizer Sector and these sectors have indicated their tentative gas requirement during the Tenth Plan. Both these sectors would strongly dictate the growth in gas demand and therefore the progress of reforms in these sectors are critical for the development of gas markets.

The summary of various gas demand scenarios/estimates is given below:

Sl. No.	Estimate	Terminal year of X plan (2006-07)
1.	Gas linkage committee committed supply + Potential demand by existing market	180.0
2.	Hydro carbon vision – 2025 *	231.0
3.	ADB's Gas master plan **	185.0
4.	Initial assessment by user ministries + other sectors ***	135.0

* The long term gas demand was also estimated by the subgroup on gas hydrocarbon vision – 2025. The subgroup on gas also had representative from CEA, NTPC, Planning commission, Fertilizer Association of India, public sector units and private and foreign companies etc.

** Under technical assistance programme of ADB a comprehensive gas sector study was undertaken. The natural gas development master plan study was completed in March, 1999.

*** As per estimates provided by The Ministry of Chemical and Fertilizer, Ministry of Power, Department. of Chemicals and Petrochemicals and Department of Fertilizers have also indicated their requirements of C2/C3 and natural gas.

Supply projections

As per the supply group estimates, the overall gas production is expected to increase from 84.11 MMCD in terminal year of 9th plan (2001-02) to about 103.08 MMCD in terminal year of tenth plan (2006-07). In other words a 24% increase in domestic gas production is expected at the end of 10th plan compared to terminal year of 9th plan. [***Source***: http://planningcommission.nic.in/plans/planrel/fiveyr/9th/vol2/v2c6-3.htm, Volume 2 chapter 7.3 of Tenth Five year Plan of India; http://planningcommission.nic.in/plans/planrel/fiveyr/10th/default.htm)]. The gas production by private /JV projects is expected to almost triple compared to production achieved in terminal year of 9th plan. The table below gives the domestic gas production for the tenth five year plan.

Organization	2002-03	2003-04	2004-05	2005-06	2006-07
a. ONGC	65.50	63.3	62.22	58.83	57.03
b. OIL	6.01	6.4	6.61	7.69	7.80
c. Private/JV					
C.1 Firm	55.05	19.3	26.62	26.62	29.40
C.2 Possible	-	1.4	8.39	8.85	8.85
Total (a+b+c.1)	86.56	89.0	95.45	93.14	94.23
Total (a+b+c.1+c.2)	86.56	90.5	103.84	101.99	103.08

(***Source***: Volume 2, Chapter 7.3, page 773 of Tenth Five Year Plan, http://planningcommission.nic.in/plans/planrel/fiveyr/10th/default.htm)
The above table does not take in to account gas available from the new discoveries in KG basin.

Domestic gas availability for the market is expected to increase from about 66.18 MCMD in the terminal year of 9th plan to a peak of about 89.70 MCMD in 2004-05 and there after decline to 85.80 MCMD in the terminal year of 10th plan.

The major increase in domestic gas supplies is projected to come from the fields /discoveries of private and JV companies. This increase would mainly come from development of fields in western region and from further development of Ravva field on the eastern coast. Some new discoveries in the deep water eastern offshore are also expected to go on stream during later part of 10th plan, thereby adding to the domestic supplies. In addition, the recent gas discoveries in KG basin in Andhra Pradesh by Reliance, Cairn and recently by ONGC are expected to significantly augment the gas supply position in India in general and AP in particular. (***Source***: http://www.indiaenews.com/business/20061216/32796.htm; and www.cairn-energy.plc.uk/downloads/05S0559KE00.pdf)

Gas Market in Andhra Pradesh

In the state of Andhra Pradesh, the demand from consumers having firm committed supply in the year 2001-2002 was 6.12 MCMD. Against this the availability from GAIL for the year 2001-2002 was 7.50 MCMD.

Gas availability from the new discoveries in Krishna Godavari Basin

The Sankar Committee on Utilization of Natural Gas in Andhra Pradesh, constituted by the Government of Andhra Pradesh (GoAP) in May 2003 observed that the established reserves in KG basin as on April 1, 2002 was about 45.59 BCM with the production rate of about 7.50 MCMD (***Source:*** (http://www.infraline.com/ong/default.asp?URL1=/ong/naturalgas/utilisation/SankarCommRepUtilisNatGasMay03.asp&idCategory=4798#infra).

These existing reserves are expected to be augmented further by the recent gas discoveries in the basin. Under the new Exploration Licensing policy of Government of India, Reliance and Cairn Energy announced discoveries of gas in the KG basin with large estimated reserves. The Reliance group and its partner, Niko Resources announced a large deepwater gas discovery of twenty kilometers offshore in the KG basin on block KG_DWN_98/3. The total volume of gas reserves discovered by Reliance is estimated to be about 219.70 BCM.

Besides Reliance, Cairn Energy drilled a series of wells in the year 2001 on a Krishna Godavari Block that is to the southwest and adjacent to the Reliance block where the large discovery was made. The company has signed a heads of agreement (HOA) with GAIL for the sale of gas to GAIL for the Andhra Pradesh market. The HOA provides that Cairn and GAIL will on an exclusive basis enter into discussion to sign the gas sales agreement. These new discoveries are summarized in the following table.

Block	Company	Estimated Reserves (BCM)	Date of Discovery
KG-DWN-98/2	Cairn	21.20	June 2001
KG-DWN-98/3	Reliance	116.10	October 2002
KG-DWN-98/3	Reliance	4.50	October 2002
KG-DWN-98/3	Reliance	99.10	October 2002
Total		**240.90**	

Consequent to these discoveries, the reserves in KG basin is estimated to increase from 45.59 BCM (as on April 1, 2002) to about 286.49 BCM when the above fields commence commercial operation. Further, according to the Directorate General of Hydrocarbons (DGH) under the MOPN, ONGC has also discovered gas in the KG basin recently. It may be noted that the discovery by Reliance stands as the biggest gas find in India in three decades, and was among the World's largest gas discoveries in the year 2002. This is also the first ever discovery by an Indian private sector company. Reliance has till date drilled only 20% of the total block area awarded to them in the basin. Further, it may be noted that out of the total reserves discovered by Reliance in KG basin, according to estimates of Degolyer and MacNaughton (D&M), considered Worldwide as the most reliable authority in petroleum consultancy, the technically proven reserves is estimated to be about 96.28 BCM. The balance is in the probable and possible reserves category. According to the Sankar Committee on Utilization of Natural Gas in Andhra Pradesh, production from the Reliance field is expected to be about 40 MCMD and is expected to commence from 2005-06 onwards subject to setting up of the requisite facilities and pipelines and materializing of demand. Reliance has declared the gas find as commercial and submitted its Commerciality Report to DGH. DGH has approved the Commerciality Report. Reliance is also expected to submit the Development plan shortly.

As per recent media reports, Reliance proposes to market the gas primarily in the following regions of the country:

- East Coast: The target state will largely be Andhra Pradesh. The GOAP is also reportedly keen to ensure at least 50% utilization of this gas within the state (as noted earlier, power and fertilizer industries are the primary consumers of gas in the state)
- West Coast: Reliance proposes to bring the gas up to Goa, Mumbai, Pune and Dabhol areas via Sangli and Kolhapur in Maharashtra
- South: The southern region is also targeted for marketing the gas in Chennai and Bangalore areas along with the NTPC power plant in Kayamkulam.

Reliance has indicated that concurrent with gas exploration and production in the KG basin, Reliance would be building a gas transmission infrastructure to take gas to industrial, commercial and household consumer by the year 2005-06. For the above purpose, a network of cross-country gas pipelines would have to be constructed for transmission of gas.

Hence, it can be concluded that further capacity additions to the already existing Natural Gas reserves are happening in the Krishna Godavari Basin in the state of Andhra Pradesh. Moreover, it can also bee seen

that the demand projection is less than the supply projection for Natural Gas. Hence, it can be concluded that there will not be any price inelastic supply constraint happening due to the project activity.

The project activity is slated to draw NG coming from KG basin. The project activity has contracted NG supply for more than that required at the design PLF not from an existing gas source but from a new gas source i.e. KG Basin. The NG to be used in this project is therefore not a result of diversion of NG destined for other projects in any region. For the purpose of gas supply a priority list for allocation has been created by Gas allocation committee of MoP&NG. The fact that this project activity figures in the allocation list of NG supply, proves that the planned gas consumption of this project activity, will be met by the NG available from the KG basin. The source of NG is a bonafide gas find as has been borne out by publicly available information - The Sankar Committee on Utilization of Natural Gas in Andhra Pradesh, constituted by the Government of Andhra Pradesh in May 2003 observed that the established reserves in KG basin as on April 1, 2002 was about 45.59 BCM[12].

Reliance Industries Limited (RIL) in October, 2002 found 9 Trillion cubic feet (tcft) of gas reserves, the biggest gas find in India in three decades, in the exploration block called KGBDW-6 (renamed as KG-DWN-98/3) in deep waters, 150 km off the Andhra Pradesh Coast near Kakinada. Cairn Energy also announced discovery of about 1 tcft of gas in Krishna Godavari Basin. The present estimates indicate that RIL can supply 40 MMSCMD of gas per day after all the facilities are built and gas transported to landfall point near Kakinada. ONGC, Gujarat State Petroleum Corporation Ltd. and Reliance Industries Limited are further intensifying exploration for gas, both onshore and offshore in Krishna Godavari Basin and this is expected to result in considerable additions to gas availability[13]. Further planned projects and national NG grid and trans-national pipelines will make gas availability possible[14].

Further, the announcement of consideration of Lanco's Kondapalli[15] and NTPC's Ratnagiri Power[16] projects by Ministry of Petroleum (Government of India) for NG allocation, after NG allocation was committed to this project activity, prove that the project in question is not depriving any other future user. The fact that the two projects mentioned above are of comparable capacity to the concerned power project, proves that future power projects of same scale have not been negatively affected by the NG to be used in the project activity plant.

Further, as per the earlier discussed guidance from CDM-EB (AM_CLA_0091), it is proposed to monitor the existing natural gas user to show that the gas is not diverted from them to the project activity[17]. Also equivalent size future capacity addition (taking project activity plant's 469 MW, another 1000 MW is considered comparable) will be shown to have been received new gas supply agreement after the project activity has started operations.

---

[12] http://www.infraline.com/ong/default.asp?URL1=/ong/naturalgas/utilisation/SankarCommRepUtilisNatGasMay03.asp&idCategory=4798#infra

[13] Department of Industries, Govt. of AP; http://www.apind.gov.in/industsectors.html

[14] http://www.pwc.com/extweb/pwcpublications.nsf/docid/5EBE732379E5428ECA257184005E7A2B/$file/oil_gas.pdf

[15] http://petroleum.nic.in/clip4151206.pdf

[16] http://economictimes.indiatimes.com/News_by_Industry/Former_Enron_plant_to_get_Rel_gas/articleshow/379235

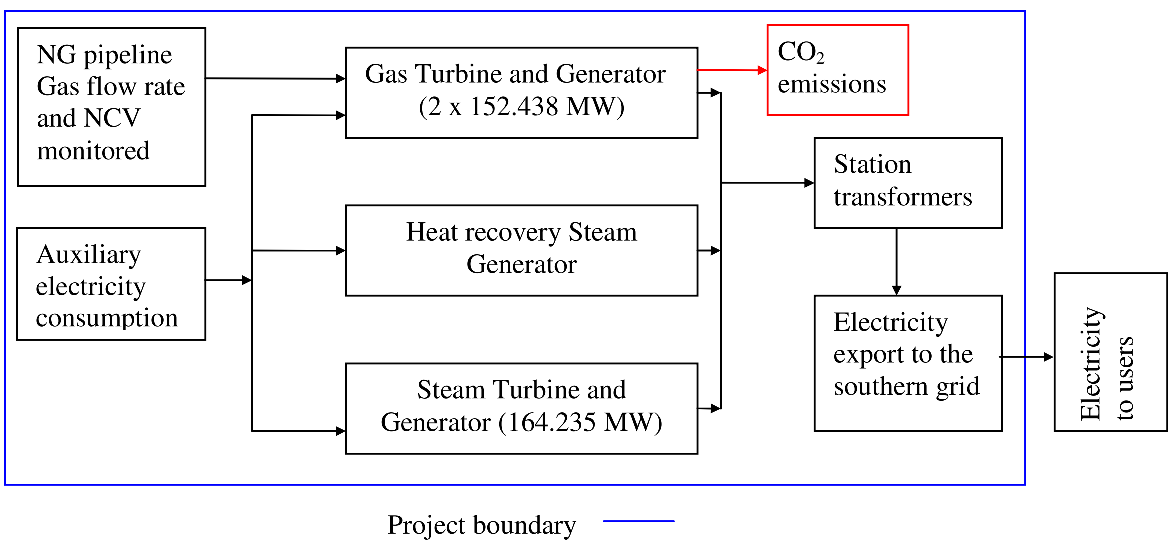
[17] A detailed gas availability and future gas based power capacity addition monitoring plan is presented to DOE

The project activity will use only use natural gas and no other fuel will be used during the start up or in co-firing. Thus, the methodology is applicable to the project activity and its use is justified here.

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

According to methodology AM0029, the spatial extent of the project boundary includes the project site and all power plants connected physically to the baseline grid as defined in "Tool to calculate the emission factor for an electricity system".

Since the project activity is connected to the regional grid, it is also preferred to take the Southern regional grid as project boundary than the state boundary. It also minimizes the effect of inter state power transactions, which are dynamic and vary widely. Thus the project boundary comprises the project site and all power plants connected physically to the southern grid. The specific components and facilities included in the project boundary are (1) Gas Turbine -two (2) Heat recovery steam generator – two (3) steam turbine generator – one (4) Station transformers (5) Auxiliary equipments of Gas Turbine and Generator, Heat Recovery Steam Generator and Steam Turbine and Generator; meters (gas, electricity) and gas supply pipelines.



	Source	Gas	Included/ Excluded	Justification/Explanation
Baseline	Power Generation in baseline	CO_2	Included	Main emission source
		CH_4	Excluded	Excluded for simplification. This is conservative.
		N_2O	Excluded	Excluded for simplification. This is conservative.
Project Activity	On-site fuel combustion due to the project activity	CO_2	Included	Main emission source
		CH_4	Excluded	Excluded for simplification.
		N_2O	Excluded	Excluded for simplification.

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

The project activity is construction and operation of 469 MW natural gas fired combined cycle power plant for supplying to grid. The alternatives will be of similar scale power plants and are discussed below.

The following is a flow chart indicating the flow of various steps involved in identifying and describing baseline scenario in accordance with AM0029.

Step -1: Identification of plausible baseline scenarios

↓

Step 2: Identification of the economically most attractive baseline scenario alternative

Further, for the purpose of identifying the economically most attractive baseline scenario alternative the following sub-steps are involved.

Sub-step 1: Calculating suitable financial indicator for identified plausible baseline scenarios

↓

Sub-step 2: Sensitivity analysis of identified plausible baseline scenarios

Baseline scenario identification as per the requirements of AM0029 leads us to the following assessment at the start of the project activity.

1. Identify plausible baseline scenarios

As required under AM0029 Version 03, the approach 48 (b) of CDM modalities and procedures "*Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment"* is being used to determine the baseline scenario.

The purpose of the project activity is to generate electricity and deliver it to the southern grid to cater to the base load power requirement of the grid.

The various possible alternatives available with the project proponent at the time of investment decision (August 2003), include the following:

S. N.	Alternative to project activity	Discussion
1	The project activity i.e.	The purpose of the project activity is to generate electricity from the Natural Gas and deliver it to the Southern Grid to meet the base load power requirement of the

	469 MW NG based Combined Cycle power plant with an efficiency of 50%-55% and with a lifetime of 15 years not taken as a CDM project activity.	grid. This alternative is in compliance with all the applicable legal and regulatory guidelines. Hence this option can be a part of the baseline scenario.
2	Power generation using Natural Gas as the fuel but with different alternative technologies	The different possible technologies that are available with the project proponent to generate power using natural gas as the fuel include b.1) Power generation using Combustion Turbine with an installed capacity of 469 MW (ISO Conditions) with an efficiency of 38% using Open cycle mode of operation with a lifetime of 20 years. This alternative generates electricity using Natural Gas as the fuel and can cater to the base load demand of the southern grid but has lower system efficiency compared to the project activity. As the option has lower system efficiency in comparison to the power generation using Combined Cycle mode of operation, it is not a realistic and credible alternative to the project proponent to opt for open cycle mode of operation for high capacities such as the case of project activity. A report of the CEA's 'Performance Review of Thermal Power Stations 2006-07 Section-10' shows that not a single NG based power plant is commissioned using open cycle after 2000. The similar report in 2007-08 says 'Use of combined cycle operation in the field of Gas Turbines is being promoted for energy conservation.[18]' Having lower efficiency will result in higher fuel consumption making operations unviable even compared to the project activity. Thus, open cycle based power plant is not a credible alternative. Therefore this alternative cannot be a part of the baseline scenario. b.2) Power generation using Gas Turbine in Cogeneration mode of operation. This alternative generates both steam and electricity from Natural Gas, though the thermal efficiency is very high in this mode of operation (60%)[19] the electrical efficiency is low (26%)[20] in comparison with the

[18] Reports provided to DOE

[19] www.opet-chp.net/download/wp6/Task_6_2_Paper_1.pdf

		Combined Cycle Mode of Operation (50-55%). The Cogeneration mode of operation is mainly used to provide electricity and steam for industrial facility. The purpose of the project activity is to deliver the power to the grid, whereas, this option does not deliver the similar output/ services comparable to the project activity. Hence, this is also not a credible and realistic alternative for the Project Proponent and therefore this alternative cannot be a part of the baseline scenarios.
3	Power generation using energy sources other than Natural Gas	The various alternative energy sources that can generate power other than natural gas include: 3a) Power generation using coal as the energy source with an efficiency of 34%-36%[21] with a life of 25-30 years[22] This is a realistic and credible alternative to the project proponent which delivers base load power to the grid. Hence, this is a plausible baseline scenario. 3b) Power generation using wind as the energy source with an average PLF of 20% with a life of 20 years [23]. Power generation from wind does not meet the base load requirement for the grid on a continuous basis as wind is seasonal in nature and the capacity utilization factor is very low. Due to the high uncertainty of wind, it is not a credible and realistic option for the project proponent for such high capacity comparable to the project activity. 3c) Power generation using hydro electric power plant with an average PLF of 60%[24]. The different types of hydro power projects available with the project proponent include: 3c.1) Reservoir storage based hydro power plants: This is not a plausible baseline scenario as it delivers peak-load power to the grid and not the base load power[25]. 3c.2) Run-of-river based hydro power projects Power generation from hydro is not a feasible alternative to the project activity as it involves high gestation periods and also can not meet the base load power requirement for the grid on a continuous basis due to the uncertainty of monsoons. Moreover, the hydro power projects are not

[20] www.opet-chp.net/download/wp6/Task_6_2_Paper_1.pdf
[21] http://www.iea.org/textbase/work/2004/zets/apec/presentations/sharma.pdf

[22] www.cercind.gov.in/160502/comp_bidding.pdf

[23] Maharashtra Electricity Regulatory Commission, Wind Project Tariff Order, 18/09/2003
http://www.mercindia.org.in/pdf/Annexures.pdf
[24] http://www.sandrp.in/hydropower/crtlenv_isue_wcd.pdf (pg. 5)

[25] The Base Load Fallacy, Author: Mark Diesendorf;
http://www.cana.net.au/documents/Diesendorf_TheBaseLoadFallacy_FS16.pdf

<table>
<tr>
<td></td>
<td></td>
<td>credible and realistic alternative to the project proponent due to the following reasons.
• Hydro power projects generally entail a long gestation period. In addition to this, these projects are comparatively capital intensive. In the context of resource shortages and continuing power shortages, thermal projects (coal, liquid fuel and gas), which need a relatively short gestation period, have been getting priority in fund allotments[26].
• The existing tariff formulation norms for hydro projects (based on a cost plus approach) with no premium for peaking services and the provision for 12% free power to distressed states from the initial years are also proving to be deterrents[27].
Hence, the above alternative cannot be an option for baseline scenario.</td>
</tr>
<tr>
<td>4</td>
<td>Power generation using cluster of Diesel Engine based power plants with an efficiency of 42% and a lifetime of 15 years[28]. The following table gives the list of various Diesel Engine based power plants connected to the Southern grid[29].</td>
<td>
<table>
<tr><th>Power Plant</th><th>Owner</th><th>City</th><th>State</th><th>Capacity (MW)</th><th>Year</th></tr>
<tr><td>Chennai Vasavi</td><td>CMS India Ltd.</td><td>Chennai</td><td>Tamil Nadu</td><td>4 × 50 MW</td><td>1998-1999</td></tr>
<tr><td>VVNL Yelahanka</td><td>Karnataka SEB</td><td>Bangalore</td><td>Karnataka</td><td>127.92</td><td>1993-1994</td></tr>
<tr><td>Kozhikode</td><td>Kerala SEB</td><td>Kozhikode</td><td>Kerala</td><td>128</td><td>1999</td></tr>
<tr><td>Samayanallur</td><td>Balaji Power Corp. Ltd.</td><td>Samayanallur</td><td>Tamil Nadu</td><td>106</td><td>2001</td></tr>
<tr><td>Samalpatti</td><td>Samalpatti Power Corp.</td><td>Samilpatti</td><td>Tamil Nadu</td><td>105.65</td><td>2001</td></tr>
<tr><td>Bellary DG</td><td>Shrirayalaseeme Ltd.</td><td>Bellary</td><td>Karnataka</td><td>25.2</td><td>2000</td></tr>
<tr><td>Belgaum</td><td>TATA</td><td>Belgaum</td><td>Karnataka</td><td>3 × 27.3 MW</td><td>2001</td></tr>
<tr><td>Kasargode</td><td>RPG</td><td></td><td>Kerala</td><td>21.84</td><td>1999</td></tr>
</table>
The above table shows that all the plants were installed before 2001 and lately the independent power producers (IPP) are not going for the liquid fuel based generation due to the increase in the fuel costs. The State Electricity Boards are also discouraging the IPPs to go for Liquid fuel based power plants for the same reason. The prices of petroleum products have long since been controlled by the Government of India (GoI) under the Administered Pricing Mechanism (APM) to reduce the burden on the consumers. However, in April 2002 the GoI dismantled the APM on the oil derived fuels (petrol,
</td>
</tr>
</table>

[26] Hydro Power Development in India Chapter IV.

[27] As per the decision taken by the Central Government in 1990, 12% of power from the energy generated by the power station would be supplied free of cost to those states of the region (including the state where the project is located) where distress is caused by setting up the project at the specific site, like submergence, dislocation of populations, etc. The Government of HP is seeking 12% of the deliverable energy of the project for the period starting from the date of synchronization of the first generating unit and extending up to 12 years from the date of commercial operation of the project, at 18% of deliverable energy of the project for a period of the next 18 years and thereafter at 30% of the deliverable energy for the balance of the agreement period beyond 30 years.

[28] http://mnes.nic.in/baselinepdfs/annexure2c.pdf.

[29] www.cea.nic.in/thermal/List of Thermal Power Stations in the Country.pdf

		diesel etc.) after which there has been sharp increase in their prices to match international parity prices. Hence the option is not an economically viable alternative to any individual IPP with such a large capacity as it was mandated by the Central Government that sanction of IPPs should be through the competitive bidding mechanism[30]. Moreover, the rupee dominated tariffs also fail to attract investors as observed in the Indian power sector particularly relating to the short gestation liquid fuel projects[31]. Therefore this alternative cannot be a part of the baseline scenario.
5	Power generation using Nuclear Fuel	This scenario is available only to Nuclear Power Corporation of India Limited, a 100% Government of India owned company[32], whose capacity additions are driven by the Government of India's initiatives based on its long term strategic programmes and not by the project activity. Hence, this option is not available for any of the stakeholders including the project activity. Therefore this alternative cannot be a part of the baseline scenario.
6	Electricity imports from other grids:	This is not a realistic alternative as all the other grids are themselves facing shortages in meeting the energy demands and especially at the peak demand. The monthly average peak deficit for the year 2004-05 being: Northern Region – 9.1% deficit; Eastern Region – 2.5% deficit; North-Eastern Region –13.6% deficit; Southern Region – 2.5% deficit and Western Region – 20.3 % deficit[33]. This alternative also does not deliver the same output comparable to the project activity due to the high transmission losses. Hence, this alternative cannot be a part of the baseline scenario.
7	Coal fired supercritical power plant:	The coal fired supercritical power plant is new advanced technology. However, the technology was not available in India in 2003 (at the time of project activity decision was made). The first supercritical power plant in India was being built in 2006 [34, 35].

From the above discussion it is evident that the plausible baseline scenarios identified by the Project Proponent include:

a) The project activity i.e. 469 MW NG based Combined Cycle power plant with an efficiency of 50%-55% in combined cycle mode of operation and with a lifetime of 15 years not taken as a CDM project activity.

[30] cercind.gov.in/160502/comp_bidding.pdf

[31] cercind.gov.in/160502/comp_bidding.pdf

[32] Atomic Energy Act, 1962 & news letter issued by Business Line-http://www.blonnet.com/2006/05/22/ stories/2006052202930300.hmt

[33] www.cea.nic.in

[34] Suresh et al., 2006. Advances in Energy Research. http://www.ese.iitb.ac.in/aer2006_files/papers/031.pdf

[35] http://goliath.ecnext.com/coms2/summary_0198-211733_ITM

b) Power generation using coal as the energy source with an efficiency of 35%-38% with a life of 25-30 years

The baseline methodology AM0029, pg 2 under the 'Identification of the baseline scenario' requires '***the baseline scenario candidates identified may not be available to project participants, but could be other stakeholders within the grid boundary** (e.g. other companies investing in power capacity expansions). Ensure that all relevant power plant technologies that have recently been constructed or are under construction or are being planned (e.g. documented in official power expansion plans) are included as plausible alternatives.*'

There were two coal based IPP projects under development in Andhra Pradesh with same power purchaser (APTransco) (1) 2x260 MW coal-based plant of BPL Power Projects (AP) Ltd. at Ramagundam[36] (2) 2x520 MW Visakhapatnam Power Project by Hinduja National Power Corpn. Ltd.[37] Thus, the coal based power plant option was available to other stakeholders in the grid. Further, in January 2002, GVK was awarded coal mine for an under consideration 500 MW subcritical coal based power plant. Thus, the opion of developing a subcritical coal based power project was also a credible alternative.

A number of actions are needed to assess the feasibility of a project including EPC contract, PPA, FSA, environmental clearances etc. Thus, these different steps were also taken by PP to study the feasibility of a power project and the public hearing referred was part of this feasibility study. These pre-feasibility steps are needed to approach financiers including banks as evident from the letter from Bank (submitted to the DOE).

Also, in January 2002, GVK was awarded a coal mine for a 500 MW coal based power plant[38]. Thus, GVK management had the option of going for a coal based power plant instead of the CDM project activity power plant.

GVKPIL, the parent company of Gautami Power Limited had the option to decide between various investment opportunities including coal based power plants and NG power plants even as late as 2003. Hence coal is a valid option considered during the investment decision (Ref: minutes of the Board of Directors Meeting). Thus, coal can be considered a credible alternative.

2. Identify the economically most attractive baseline scenario alternative.

Sub Step -1: Calculating levelized cost of electricity production in "₹/kWh" for identified plausible baseline scenarios

The levelized cost for the alternative (a) i.e. implementing the project activity without the consideration of CDM revenue is calculated by the following assumptions:

---

[36] http://www.financialexpress.com/printer/news/63579/

[37] http://www.processregister.com/Visakhapatnam_Power/Project/pid6967.htm;

http://hindujanationalpower.com/

[38] http://coal.nic.in/alloblocklist.htm [Refer Sl. No. 19 - GVK Power (Govindwal Sahib) Ltd.]

The following table details the assumptions used for the financial calculations. All the assumptions used in the financial model are based on the inputs that were used in the financial closure obtained by the project activity.

Techno Economic parameters for project activity taken without CDM			
Parameter	**Value**	**Unit**	**Reference**
Installed Capacity	469	MW	
Total Investment	14,500	Million ₹	DPR, May 2001[39] specifies D/E ratio
Debt: Equity	70: 30	%	
Rupee Debt	5,182.28	Million ₹	
US Dollar Debt	4,968		
Exchange rate	1 USD = 46 ₹		
O&M Costs	3.76%	of the capital Cost	experience of PP from operating NG CCPP[40]
O&M US $ Portion	65%	with an escalation of 2% every annum	
O&M Rupee Portion	35%	with an escalation of 5% per annum	
Plant Load Factor	85	%	DPR (Appendix 13)
Auxiliary Consumption	3	%	DPR (Appendix 13)
Total Units Sold	50,399	Million kWh for 15 years	calculated
Gross Calorific Value	9308	kcal/SCM	DPR (Appendix 13)
Station Heat Rate	1850	kcal/ kWh	PPA of GPL 1997, Clause 57
Fuel Charges	4205	₹/ 1000 SCM	Fuel supply agreement with GAIL (09/10/2000) and applicable taxes pg. 7[41]
Transmission Charges	481.44	Million ₹	
Escalation in Transmission Charges	3	%	
Book Depreciation Rate (Straight Line Method basis)			
Plant and Machinery	8.24	%	Depreciation Norms for Generating
Book Depreciation up to (% of asset value)	90	%	

[39] DPR for power plant was made by earlier owners in 2001, and an annual project cost 13237.6 million. An annual escalation of 5% for two years till decision making is assumed

[40] (Jegurupadu phase I) and conservative compared to 3.8% considered by Project Information Memorandum for GPL by PFC in Nov. 2003 (Pg. No. 36, 39 of pdf file)

[41] matches third party value from Project Information Memorandum for GPL by PFC in Nov. 2003 (Pg. No. 100, 104 of pdf file)

			Companies by the Notification from Ministry of Power
Income Tax			
Income Tax rate	35	%	IT Act Rate applicable for decision year 2003-04
Minimum Alternate Tax	7.5	%	
Surcharge	2.5	%	
Dividend Distribution Tax	12.5	%	
Working capital			
Receivables	30	No. of days	CERC (Terms & Conditions of tariff) Regulations, 2001; Pg. 30
Working capital interest rate	11	%	RBI PLR
Working Capital Margin	25%	of working capital	
Working Capital Loan	75%		

The levelized cost of electricity generation using Natural gas as the energy source calculated using the above values comes out to be 2.08 ₹/kWh.

The assumptions considered for calculating the levelized cost of generation for the alternative (b) i.e. power generation using coal as the energy source are described in the table below. For coal based power plant, the nearest capacity in the standard available TG Set i.e. 500 MW which is used for comparison. This 500 MW plant at 85% PLF and 9.5% auxiliary consumption will generate 3,369,315MWh electricity. Whereas, a 469 MW gas based unit at 85% PLF and 3% auxiliary consumption will generate 3,387,409MWh electricity. The difference is only 0.53% (higher for the NG based unit) between the baseline and project plant.

Techno Economic parameters for power generation using coal as the energy source		
Installed Capacity	500 MW	Comparable size chosen to get same output as project activity (refer culations above this table)
Total Investment	19,974.41	Million ₹ - Estimated from TEC available to other thermal projects[42]
Debt : Equity	70:30	ratio kept at same level as the NG CCPP alernative
Total Debt	13,982.08	Million ₹ at standard D/E

[42] Close to 40 ₹ million/ MW in 2002 (http://www.cea.nic.in/Thermal/Project%20Appraisal/central-state-thermal.pdf). Another GVK Group company was also developing a 500 MW subcritical coal based project with capital cost ₹ 20,000 million (http://www.psebindia.org/pseb/docs/goindwal.htm)

Total Equity	5,992.32	Million ₹
Exchange rate	1 USD = 46 ₹	
O&M Costs + Insurance Charges	2.5% of the capital Cost + 6% escalation/ year	CERC (Terms & Conditions of tariff) Regulations, 2000; pg. 92
Plant Load Factor	85%	ratio kept at same level as the NG CCPP alternative
Auxiliary Consumption	9.5%	CERC (Terms & Conditions of tariff) Regulations, 2001; pg. 8
Total Units Sold	67,432 Million kWh for 20 years	calculated
Return on Equity	16%	CERC (Terms & Conditions of tariff) Regulations, 2001; pg. 27
Gross Calorific Value	4,760.50 kcal/kg	Price Notification No. 7/2001-2002 dated 9th April, 2001 from The Singareni Collieries Co. Ltd
Station Heat Rate-Stabilization	2,600 kcal/ kWh	CERC (Terms & Conditions of tariff) Regulations, 2001; pg. 7
Station Heat Rate- Post Stabilization	2,500 kcal/ kWh	
Fuel Charges	1,357 ₹/ 1,000 kg	Price Notification No. 7/2001-2002 dated 9th April, 2001 from The Singareni Collieries Co. Ltd.
Depreciation rate for revenue calculation (Straight Line Method basis)		
Plant and Machinery	7.84%	Electricity Supply Act
Book Depreciation up to (% of asset value)	90%	Electricity Supply Act
Book Depreciation Rate (Straight Line Method basis)		
Civil Works	3.34%	The Companies Act
Plant and Machinery	5.28%	
Surcharge	2.5%	
Dividend Distribution Tax	12.5%	
Working capital		
Receivables (no of days)	30	Values kept at same level as the NG CCPP alternative
Spares	1% of Capital Cost	
Working capital interest rate	11%	
Working Capital Margin	25% of the working capital	
Working Capital Loan	75% of working capital	

The levelized cost of electricity generation using Coal as the energy source calculated using the above values comes out to be 1.93 ₹/kWh.

The below table summarizes the levelized cost of electricity generation for various alternatives.

Sr. No.	**Baseline Scenario**	**Levelized Cost of generation (₹/ kWh) at 85% PLF**

(a)	Project activity implemented as a project without the CDM revenue	2.10
(b)	Power generation using coal as the energy source	1.93

Thus, the economically attractive baseline scenario as identified by the investment analysis using the levelized cost of electricity generation (in / kWh) as the financial indicator is the alternative (b) which is power generation using coal as the energy source.

Sub Step -2: A sensitivity analysis is performed for all alternatives; to confirm that the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions i.e. the fuel price, plant load factor, capital cost and station heat rate.

Sensitivity analysis considering variation in fuel price		
Price of fuel change	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	1.97	2.22
Levelized cost of electricity generation for power generation using coal as energy source	1.82	2.05

Sensitivity analysis considering variation in Plant Load Factor (PLF)		
PLF change	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	2.18	1.94
Levelized cost of electricity generation for power generation using coal as energy source	2.01	1.87

Sensitivity analysis considering variation in capital cost		
Capital cost change	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	2.07	2.12
Levelized cost of electricity generation for power generation using coal as energy source	1.90	1.97

Sensitivity analysis considering variation in heat rate		
Capital cost change	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	1.97	2.14
Levelized cost of electricity generation for power generation using coal as energy source	1.81	2.05

The sensitivity analysis confirms that the economically most attractive baseline scenario identified in the sub-step 1 is robust to reasonable variations in all the critical assumptions.

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

As specified in the approved methodology AM0029 Version 03, the assessment and demonstration of additionality is to be carried by the following steps.

Step 1: Benchmark investment analysis

Demonstrate that that the proposed CDM project activity is unlikely to be financially attractive by applying sub-steps 2b (Option III: Apply benchmark analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the latest version of the "Tool for the demonstration and assessment of additionality" agreed by the CDM Executive Board.

For determining the benchmark, project proponent has taken into consideration all the financial parameters relevant to the project activity and has also conducted sensitivity analysis to gauge the impact of probable realistic fluctuation of key parameters. According to the Tool for the demonstration and assessment of additionality, V 05.2, levelized cost of electricity generation can be used as financial indicator for the Benchmark Investment Analysis. This parameter is appropriate for this project activity, as all thermal electricity generation projects in the baseline grid are allowed return of 16% on equity investment in determining their cost for tariff purposes.

Also the CERC had implemented Availability Based Tariff (ABT) in all the five regions of the country at the inter-state level. The ABT facilities merit order dispatch of various generating stations having different variable costs. Hence in such a competitive bidding scenario it is very important for the IPP to have a low cost of power generation. Thus, the levelized cost of generation is the most appropriate financial indicator.

The levelized cost of electricity generation for the project activity and the levelized cost of electricity generation of the baseline scenario (i.e. power generation using Coal as the energy source) are compared with the average cost of generation in central sector coal stations in 2004[43]. The following table summarizes the results of the comparison.

Sr. No.	Alternatives	Levelized Tariff (₹/kWh) at 85% PLF
(a)	Project activity implemented as a project without the CDM revenue	2.10
(b)	Power Generation using coal as the energy source (Baseline Scenario)	1.93
(c)	Average cost of generation in central sector coal stations in 2004	1.42[44]

From the above table it can be seen that Coal based power generation is the most financially attractive alternative. Also it can be seen that project activity without CDM revenue is not the most financially attractive option making it uncompetitive.

Sub-step 2(d)
A sensitivity analysis is performed to confirm that the conclusion regarding the financial attractiveness is robust to reasonable variations in the critical assumptions i.e. the fuel price and the plant load factor.

43 www.indiastat.com (original data provided to DOE)

44 www.indiastat.com (original data provided to DOE)

Sensitivity analysis considering variation in fuel price		
Price of fuel	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	1.97	2.22
Benchmark - Average cost of generation in central sector coal stations in 2004	1.42	

Sensitivity analysis considering variation in Plant Load Factor (PLF)		
PLF	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	2.18	1.94
Benchmark - Average cost of generation in central sector coal stations in 2004	1.42	

Sensitivity analysis considering variation in capital cost		
Capital cost change	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	2.07	2.12
Benchmark - Average cost of generation in central sector coal stations in 2004	1.42	

Sensitivity analysis considering variation in heat rate		
PLF	-10%	+10%
Levelized cost of electricity generation for power generation using natural gas as energy source (Project activity not implemented as CDM Project)	1.97	2.14
Benchmark - Average cost of generation in central sector coal stations in 2004	1.42	

The sensitivity analysis also confirms that under all the possible scenarios, the levelized cost of electricity generation of the project activity is much higher than the benchmark and the baseline scenario both and hence making the project activity uncompetitive without CDM revenue.

Hence from the above it can be concluded that the Baseline scenario – Coal based power generation is the most financially attractive option and the project activity - Natural gas based power generation without CDM revenue is not the most financially attractive option.

Step 2: Common Practice Analysis.
Prevalence of NG based power plants in the Indian scenario:

The following table represents the total installed capacity in India and the share of the coal based power plants and natural gas based power plants[45].

Region	Total Thermal Power Generation, (MW)	Generation using Coal as fuel (MW)	% generation using coal as fuel of the thermal power generation	Generation using gas as fuel (MW)	% generation using gas as fuel of the total installed capacity

[45] CO_2 baseline database for the Indian power sector, User guide, Version 3.0, December 2007, Central Electricity Authority, Government of India, p. 2.

Northern	21775.68	18,327.50	84.2	3433.19	15.8
Western	30120.7	23502.5	78.0	6600.72	21.9
Southern	20708.12	23502.5	113.5	3568.3	17.2
Eastern	15357.08	15149.88	98.7	190	1.2
North Eastern	1244.24	330	26.5	771.5	62.0
Island	70.02	0	0.0	0	0.0
All India	89275.84	73492.38	82.3	14581.71	16.3

As it can be seen from the table, the share of the gas based power generation in India is 16% of the total installed thermal power capacity and that of coal based power plants is 82%. The total % of installed capacity of the gas based power plants in Southern Region is only 17.2% of the total installed capacity. This corroborates the fact that Natural Gas based power generation is not commonly carried out practice in India.

According to the 'Tool for the demonstration and assessment of additionality', analysis of any other activities implemented previously or currently underway that are similar to the proposed project activity needs to be performed to describe whether and to which extent similar activities have already diffused in the relevant region. Similar project activities include Natural gas based Grid Connected Power Plant

- of similar scale
- that takes place in a comparable environment with respect to regulatory framework, investment climate, and access to technology etc., in the state of Andhra Pradesh with the tariff determined through the International Competitive Bidding Process (ICB).
- those activities that are implemented previously or currently underway

To arrive at the power plants that fall under the above said criteria, an analysis is conducted including all the power plants connected to grid that are operational having similar or comparable capacity (200- 500 MW) at the time of investment decision. They include

S.NO	Power generation units	Unit No.	Capacity	Fuel used
1	K_gudem new	1	250	Coal
2	K_gudem new	2	250	Coal
3	Vijaywada	1	210	Coal
4	Vijaywada	2	210	Coal
5	Vijaywada	3	210	Coal
6	Vijaywada	4	210	Coal
7	Vijaywada	5	210	Coal
8	Vijaywada	6	210	Coal
9	Rayal seema	1	210	Coal
10	Rayal seema	2	210	Coal
11	R_gundem stps	1	200	Coal
12	R_gundem stps	2	200	Coal
13	R_gundem stps	3	200	Coal
14	R_gundem stps	4	500	Coal
15	R_gundem stps	5	500	Coal
16	R_gundem stps	6	500	Coal
17	Simhadri	1	500	Coal

18	Simhadri	2	500	Coal
19	Peddapuram ccgt	1	220	Natural gas
20	Jegurupadu I	1	235.4	Natural gas
21	Spectrum Godavari	1	208	Natural gas

Among the above mentioned power plants S.No 19, 20 and 21 are NG based power plants. Although this may use a similar fuel as compared to the project activity, the tariff structure of GPL is different as compared to that of the NG based power plant mentioned above. These power plants have a two part tariff system in which the capital cost was approved by CEA and they are entitled for a fixed return of equity[46]

In contrast to that the Power Purchase Agreement for the project activity was signed with APTRANSCO with the tariff that was fixed for the short gestation projects (Natural Gas Based Power Generation Projects) selected under the International Competitive Bid Process (ICB). The other fixed charges was fixed at ₹ 0.699 per unit of cumulative available energy and the Foreign Debt Service Charge was fixed at US $ 0.006 per unit of cumulative available energy payable at the current exchange rate. The Foreign Debt Service Charges are payable only in respect of period ending on 11th annual anniversary of the COD of the project activity[47].

The tariff fixed for the project activity was to match the tariff fixed for the Natural Gas based Power Projects which have participated in the International Competitive Bid Process. The Natural Gas based power plants that have participated in the process and won the bid for the similar tariff include

1. 370 MW Vemagiri Power Project promoted by GMR Group.
2. 445 MW Konaseema Power Project promoted by Konaseema Gas Power Limited.
3. 228 MW Combined Cycle Natural Gas based grid connected power plant promoted by GVK Industries Ltd., Hyderabad

All these projects are in different stages of CDM registration process and all of these have already been webhosted for the global stakeholder comments[48].

The plants that existed from earlier days in the vicinity namely Spectrum Power Generation and another project from the same project promoters is based on a different tariff structure to include a guaranteed 16% return on equity[49].

Thus, all the projects with similar tariff structures are in different stages of CDM registration Process.

The multifuel power plants came up in a different investment scenario and have fuel pass through PPA i.e. cost of fuel is paid to the plant under the PPA signed. The project activity PPA does not have any such arrangement and two part tariff is discussed in PDD. Naptha power plants cannot be considered in common practice.

---

[46] http://www.ercap.org/TariffOrders/TO_2001-02.pdf (Page 45)

[47] Red Herring prospectus of GVKPIL page 84 (Released on 19/01/2006)

[48] http://cdm.unfccc.int/Projects/Validation/

[49] http://www.scribd.com/doc/20623495/GVK-Power-Infrastructure-Initiating-Coverage-11Aug09 (Page 4)

As per 'Additionality Tool' – only 'similar activities' (one condition for similar being those that take place in a similar environment) need to be considered. Projects pre-2001 had different investment scenario (low project cost, fuel pass through PPA) and cannot be considered similar to this project activity for comparison under common practice evaluation requirement. It should also be noted that there has been no other Natural Gas based Power Project that has been commissioned in Andhra Pradesh with the similar tariff structure. Hence, it can be concluded no similar activities have diffused in the relevant region without the consideration of CDM revenue.

The investment decision making body at the board level had seriously considered CDM revenue for the financial viability in approving the project activity. The board meeting where financial approval for the project activity was given considering the CDM revenue was held on 25/08/2003[50].

The explanation for the delay in processing for the CDM registration process as presented as below

S. N.	Date	Project Execution Step	CDM registration efforts	Evidence
1	04/01/2003	-	Meeting of the PP's team with CDM consultant – *prior awareness*	Minutes of the meeting
2	25/08/2003	Board meeting of Gautami Power Ltd. for the investment decision in project considering prospect of CDM revenue	The Board considered CDM revenue for the project viability	minutes of Board of Directors' meeting
3	27/09/2003	Award of the EPC Contract to Alstom Projects India Ltd.	-	Copy of EPC contract
4	01/07/2004	Financial closure for the project activity and notice to proceed to the EPC contractor[51]	**Start date of the CDM project activity**	Copy of NTP letter
5	11/02/2005	-	ERPA for sale of CERs from the project activity	Copy of Emission Reduction Purchase Agreement
6	23/11/2005	Environmental clearance from Ministry of Environment and Forests, Government of India	-	Copy of EC from MOEF
7	28/03/2006	Consent for Establishment (CFE) amended by state pollution control board	-	Copy of amended CFE
8	04/01/2007	-	Appointment of the CDM consultants	Copy of agreement
9	30/11/2007	-	Local Stakeholders	Minutes of the meeting

[50] Minutes of the Board meeting are available for validation

[51] Letter of Notice to Proceed is provided to the EPC contractor

			consultation meeting	
10	04/12/2007		Expiry of ERPA	Copy of the letter from the ER buyer.
11	03/07/2008	-	Submission of PDD for validation[52]	Copy of email
12	17/09/2008	-	PDD was web hosted for GSC	UNFCCC-CDM web site Validation link
13	21/08/2008	-	PDD submitted for Host Country Approval, meeting on 16/10/2008 and Approval award on 06/02/2009	Host Country Approval letter
14	05/06/2009	Commissioning of the project activity plant	-	COD approval from Andhra Pradesh Power Coordination Committee
15	13/09/2009	Appointment of present DOE	-	-
16	30/12/2009	PDD web hosted for global stakeholder comments	-	CDM validation web site[53]

The start date of the project is notice to proceed to the EPC Contractor along with the first installment for the EPC contract value i.e. 30/06/2004. Within less than one year from the start date, an emission reduction purchase agreement was entered into for sale of CERs from the project activity. Thereafter, within two years, a CDM Consultant is contracted for the CDM registration of the project activity. Thus, documented evidences to secure the CDM status are in line with EB49, Annex 22, clause No. 7 and 8.

Based on the above discussions, it can be concluded that the project activity is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

According to the approved methodology AM0029 Version 3

Project emissions

The project activity is on-site combustion of natural gas to generate electricity. The CO_2 emissions from electricity generation (PEy) is calculated as follows:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$

$FC_{f,y}$: is the total volume of natural gas or other fuel ‘f’ combusted in the project plant or other startup fuel (m^3 or similar) in year(s) ‘y’

[52] The PDD was web hosted for the global stakeholder comments from 17/09/2008 to 16/10/2008. The validation services agreement with the earlier DOE is terminated with a NOC.

[53] http://cdm.unfccc.int/Projects/Validation

$COEF_{f,y}$: is the CO_2 emission coefficient (tCO_2/m^3 or similar) in year(s) for each fuel and is obtained as:

$$\mathbf{COEF_{f,y} = \Sigma NCV_{f,y} * EF_{CO2f,f,y} * OXID_f}$$

Where:

$NCV_{f,y}$: is the net calorific value (energy content) per volume unit of natural gas in year 'y' (GJ/m^3) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

$EF_{CO2,f,y}$: is the CO_2 emission factor per unit of energy of natural gas in year 'y' (tCO_2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

$OXID_f$: is the oxidation factor of natural gas

Baseline emissions

Baseline emissions are calculated by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

$$BE_y = EG_{PJ,y} \cdot EF_{BL,CO2,y}$$

According to the approved methodology AM0029, project participants shall use for $EF_{BL,CO2,y}$ the lowest emission factor among the following three options:

For the first crediting period:

Option 1. The build margin, calculated according to "Tool to calculate emission factor for an electricity system"; and

Option 2 The combined margin, calculated according to "Tool to calculate emission factor for an electricity system", using a 50/50 OM/BM weight.

Option 3 The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above, and calculated as follows:

$$EF_{BL,CO2}(tco2/Mwh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

where,

$COEF_{BL}$ = the fuel emission coefficient (tCO_2e/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used

η_{BL} = the energy efficiency of the technology, as estimated in the baseline scenario analysis above.

For the option 1, the build margin is calculated by the Central Electricity Authority (CEA,Version 05) India according to the procedures prescribed in the approved methodology ACM0002. We have referred the same value for the baseline calculation.

For option 2, the combined margin is calculated with a 50/50 OM/BM weights. The Operating Margin (OM) and the Build Margin (BM) has been calculated by the Central Electricity Authority (CEA,) India according to the procedures prescribed in the approved methodology ACM0002. We have referred the same value for the baseline calculation.

For option 3, coal fired power plant using conventional i.e. sub-critical technology has been identified in section B.4. as the economically most attractive baseline scenario alternative due to its lowest levelized electricity generation cost, whose emission factor are calculated in accordance with and as per equation 4 of AM0029.

Leakages

As per the approved methodology AM0029, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y}$$

where:

LE_y Leakage emissions during the year y in tCO_2e

$LE_{CH4,y}$ Leakage emissions due to fugitive upstream CH_4 emissions in the year y in tCO_2e

$LE_{LNG,CO2,y}$ Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e

Fugitive methane emissions

According to the approved methodology AM0029, the fugitive methane emissions are calculated as follows:

$$LE_{CH4,y} = \left[FC_y \cdot NCV_y \cdot EF_{NG,upstream,CH4} - EG_{PJ,y} \cdot EF_{BL,upstream,CH4}\right] \cdot GWP_{CH4}$$

where:

$LE_{CH4,y}$ Leakage emissions due to fugitive upstream CH_4 emissions in the year y in t CO_2e

FC_y Quantity of natural gas combusted in the project plant during the year y in m³

$NCV_{NG,y}$ Average net calorific value of the natural gas combusted during the year y in GJ/m³

$EF_{NG,upstream,CH4}$ Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in t CH_4 per GJ fuel supplied to final consumers

$EG_{PJ,y}$ Electricity generation in the project plant during the year in MWh

$EF_{BL,upstream,CH4}$ Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant, as defined below

GWP_{CH4} Global warming potential of methane valid for the relevant commitment period

As the baseline emissions are calculated based on option 1 i.e. the build margin calculated by CEA in accordance with the procedures in ACM0002, the emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity is derived using the flowing equation:

$$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j}$$

$EF_{BL,upstream,CH4}$ = Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH4 per MWh electricity generation in the project plant

j : = Plants included in the build margin

$FF_{j,k}$ *:* = Quantity of fuel type *k* (a coal or oil type) combusted in power plant *j* included in the build margin

$EF_{k,upstream,CH4}$: = Emission factor for upstream fugitive methane emissions from production of the fuel type *k* (a coal or oil type) in t CH4 per MJ fuel produced

EG_j : = Electricity generation in the plant *j* included in the build margin in MWh/a

Thus, the emission factor for upstream fugitive CH_4 emissions is consistent with the baseline emission factor calculation as per option-1.

During the crediting period for fugitive CH_4 emissions associated with NG, default values provided in Table 2 of the approved methodology AM0029 are used, as reliable and accurate national data are not available. The default values to be used in relation to NG production, processing, transport and distribution from Table 2 of AM0029 is US/Canada values for NG the gas transportation and distribution facilities would be built in near future and would be built as per the international standards.

If LNG is used by the project activity plant, following formula will be used for calculation of related leakage.

$$LE_{LNG,CO2,y} = FC_y \cdot EF_{CO2,upstream,LNG}$$

Where,

$LE_{LNG,CO2,y}$ = Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in t CO_2e

FCy = Quantity of natural gas (LNG) combusted in the project plant during the year y in m³

$EF_{CO2,upstream,LNG}$ = Emission factor for upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system

The PP will use the default value i.e. 6 t CO_2/TJ as per AM0029, ver. 03 for this parameter in absence of specific data. As PP doesn not plan to use LNG presently, related leakage is considered as zero.

$LE_{LNG,CO2,y} = 0$

As there are no Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system during the year y in tCO_2e.

Upstream fugitive emissions occurring in the absence of the project activity electricity generation has been calculated using the Build Margin power plants. Therefore in line with the AM0029 requirement of ex-post determination of the Build Margin, the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation (tCH4 /MWh) will also be determined ex-post.

Emission Reductions

ERy = BEy – PEy – LEy

Where:

ERy : emissions reductions in year y (t CO_2e)

BEy : emissions in the baseline scenario in year y (t CO_2e)
PEy : emissions in the project scenario in year y (t CO_2e)
LEy : leakage in year y (t CO_2e)

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

Data / Parameter:	$EF_{BM,y}$
Data unit:	tCO_2/MWh
Description:	The Build Margin emission factor of Southern grid
Source of data used:	CEA CO_2 Baseline Database, version 05; November 2009
Value applied:	0.8179
Justification of the choice of data or description of measurement methods and procedures actually applied :	The value is taken from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.
Any comment:	Latest available value for 2008-09 is used.

Data / Parameter:	$EF_{OM,y}$
Data unit:	tCO_2/MWh
Description:	The Operating Margin emission factor of Southern grid
Source of data used:	CEA CO_2 Baseline Database, version 05;
Value applied:	0.9876
Justification of the choice of data or description of measurement methods and procedures actually applied :	The value is taken from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.
Any comment:	The yearly Operating Margin emission factor of southern grid is as follows 2006-07: 0.972; 2007-08:0.99; 2008-09: 0.99; Average = 0.9876

Data / Parameter:	EF_{Coal}
Data unit:	kg CO_2e/TJ
Description:	Emission Factor of Coal
Source of data used:	CEA CO_2 Baseline Database, version 05
Value applied:	95,800
Justification of the choice of data or description of measurement methods and procedures actually applied :	The value is taken from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.
Any comment:	CEA CO_2 Baseline Database, Assumptions sheet, Cell D7

Data / Parameter:	$EF_{electricity.y}$

Data unit:	tCO_2/MWh
Description:	The Emission factor of the Southern grid
Source of data used:	Calculated as the weighted average of the build margin emission factor and operating margin emission factor (with 50/50 weights to OM and BM)
Value applied:	0.9028
Justification of the choice of data or description of measurement methods and procedures actually applied :	The values are taken from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.
Any comment:	BM 0.8179 OM 0.9875

Data / Parameter:	EF_{NG}
Data unit:	$kgCO_2e/TJ$
Description:	Emission Factor of Natural Gas
Source of data used:	Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value applied:	56,100
Justification of the choice of data or description of measurement methods and procedures actually applied :	In absence of country specific data; IPCC default value used as recommended in methodology.
Any comment:	--

Data / Parameter:	$Oxid_{Coal}$
Data unit:	Unit less factor
Description:	Oxidation Factor of Coal
Source of data used:	IPCC Default Value
Value applied:	1
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value used in absence of country specific data (Reference - Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories)
Any comment:	--

Data / Parameter:	$Oxid_{NG}$
Data unit:	Unit less factor
Description:	Oxidation Factor of NG
Source of data used:	IPCC Default Value
Value applied:	1

Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value used in absence of country specific data (Reference - Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories)
Any comment:	IPCC Default Value

Data / Parameter:	NCV_{Coal}
Data unit:	kcal/ kg
Description:	Net Calorific Value of Coal
Source of data used:	GCV and conversion factor (GCV to NCV) sourced from "CO_2 Baseline Database of the Indian Power Sector, Version 5.0 issued by Central Electricity Authority, Ministry of Power, Government of India" (http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm)
Value applied:	3,625
Justification of the choice of data or description of measurement methods and procedures actually applied :	The data used is from a national level and publicly accessible source and has a high level of reliability.
Any comment:	--

Data / Parameter:	$EF_{NG, Upstream,CH4}$
Data unit:	t CH_4/GJ
Description:	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in tCH_4 per GJ fuel supplied to final consumers.
Source of data used:	Table 2, page 8 of the approved methodology AM0029
Value applied:	296
Justification of the choice of data or description of measurement methods and procedures actually applied :	In the absence of country specific values, the reference value from the approved methodology AM0029 is used as a conservative estimate.
Any comment:	--

Data / Parameter:	$EF_{CO2, Upstream,LNG}$
Data unit:	tCO_2/TJ
Description:	Emission factor for upstream CO_2 emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas

	transmission or distribution system
Source of data used:	Page 10, Paragraph 1 of the approved methodology AM0029 (Ver. 03)
Value applied:	6
Justification of the choice of data or description of measurement methods and procedures actually applied :	In the absence of country specific values, the reference value from the approved methodology AM0029 is used as a conservative estimate.
Any comment:	--

Data / Parameter:	$EF_{BL,\ Upstream,CH4}$
Data unit:	t CH_4/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in terms of ton of methane per MWh
Source of data used:	Calculated as: $$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j}$$ $FF_{j,k}$: Refer to "Fuel consumed by power sources" under section B.7.1. $EF_{k,upstream,CH4}$: Table 2 of AM0029 EG_j : Refer to "Electricity delivered to grid " under section B.7.1
Value applied:	15.72 tonnes CO_2/MU
Justification of the choice of data or description of measurement methods and procedures actually applied :	Wherever necessary default values suggested in the approved methodology AM0029 are used in the formula above to arrive at the above value. e.g. Fugitive methane emission factor for coal production = 0.8 (for surface mining, as most of the coal production in India comes from open pit mines contributing over 81% of the total production[54])
Any comment:	Calculated using CEA CO_2 Baseline Database version 5.0

Data / Parameter:	η_{BL}
Data unit:	% points
Description:	The energy efficiency of technology in the most likely baseline scenario.
Source of data used:	Calculated from the actual electricity generation and fuel consumption data from CEA CO_2 Baseline Database, version 5.0
Value applied:	33.3
Justification of the choice of data or description of measurement methods and procedures actually applied :	The values are calculated from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.

[54] http://www.mbendi.co.za/indy/ming/coal/as/in/p0005.htm

Any comment:	See Annex 3 for calculations

B.6.3 Ex-ante calculation of emission reductions:

1. Calculation of baseline emissions

To calculate the baseline emissions the lowest of the three values amongst the build margin, combined margin and the emission factor for the most likely baseline scenario is taken as the baseline CO_2 emission factor.

A) Build margin

The build margin is calculated by the Central Electricity Authority (CEA) India according to the procedures prescribed in the "Tool to calculate emission factor for an electricity system". Thus, the value taken is 817.9 tCO_2e/GWh.

B) Combined margin

The combined margin is calculated with a 50/50 OM/BM weights. The Operating Margin (OM) and the Build Margin (BM) has been calculated by the Central Electricity Authority (CEA,) India according to the procedures prescribed in the "Tool to calculate emission factor for an electricity system". The Operating margin is fixed ex-ante and is taken as the average of the recent three years of data given by the CEA at the time of PDD submission (i.e. for the years, 2006-2007 and 2007-2008, 2008-2009). The value applied for Operating Margin is 987.6 tCO_2/GWh. The value applied for the build margin is 817.9 tCO_2e/ GWh. The value applied for the combined margin is 902.8 tCO_2e/GWh.

C) Emission factor of the most likely baseline scenario.

Calculated as per equation 3 of AM 0029 where the most likely baseline scenario is identified as the coal based power plant

Values of sub-variables are as follows

Fuel CO_2 emission co-efficient ($COEF_{BL}$): 0.0958tCO_2e/GJ

Energy Efficiency of technology (η_{BL}): 33.3%

Thus,

$EF_{BL,CO2}$ = 0.0958 t CO_2e/GJ* 3.6 GJ/MWh *1000/0.333 = **1036**t CO_2/GWh

Therefore, according to AM0029, the lowest value among the three options is **817.9** t CO_2/GWh (i.e. Build Margin) is chosen as baseline emissions factor $EF_{BL,CO2,y}$.

Project activity's electricity generation (i.e. net evacuation to the grid) EGy is estimated as 3387.4 GWh per year. The value is arrived from the installed capacity 469 MW operating 24 hrs a day, 365 day a year at 85% PLF and 3% auxiliary consumption (i.e. 469 x 24 x 365 x 85% x (100-3)% / 1000 =3387 GWh

Therefore, the estimated annual baseline emissions (BE_y) will be (as per equation 3 of AM0029)

BE_y = 3387.4 GWh * 817.9 tCO_2/GWh = **2,770,562** tCO_2

2. Calculation of Project Emissions (PE_y)

Calculated as per equation 2 of AM0029 as contained in part A (procedure followed for estimating emissions in the project scenario) of section B.6.1 "Explanation of Methodological Choices".

The value of project emissions is 1,379,231 t CO_2e/ year

Values of sub-variables are as follows
Volume of fuel combusted in project plant in year y ($FC_{f,y}$) : 685,321,088 SCM
CO_2 emission coefficient of fuel ($COEF_{f,y}$) : 0.0020 t CO_2/ m^3 of natural gas
Based on the above, the estimated annual project emissions (PE_y) will be
PE_y = 0.0020 tCO_2/SCM * 685,321,088 SCM = 1,379,231tCO_2/ year

Sub-variables are calculated as follows
Calculation of CO_2 Emission Co-efficient of natural gas ($COEF_{f,y}$)
Calculated as:
CO_2 Emission Co-efficient of natural gas is calculated as per equation number-2a of AM 0029 Values of sub-variables:
1) Net Calorific Value of gas (NCV_y): 8570 Kcal/SCM
2) CO_2 emission factor ($EF_{CO2,f,y}$): 0.0561 t CO_2/GJ
3) Oxidation factor of gas ($OXID_f$): 1
8570 kcal/SCM * 4.186 * 10^{-9} * 56.1 t CO_2 / TJ * 1 = **0.0020 tCO_2/ m^3**

3) Calculation of Leakages (LE_y)

Leakages are calculated as per equation number-5 of AM 0029 as contained in part C (procedure followed for estimating Leakages) of section B.6.1 "Explanation of Methodological Choices", which is **97,909** tCO_2e

1) Leakage emission due to fugitive upstream CH_4 emissions ($LE_{CH4,y}$): **97,909**tCO_2e.
2) Leakage emissions due to fossil fuel combustion/electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) : 0 tCO_2 in the present case

Based on the above, the estimated annual leakages (LEy) will be
= **97,909**+ 0 t CO_2 e = **97,909** tCO_2e

3A) Calculation of leakage emissions due to fugitive upstream CH_4 emissions ($LE_{CH4,y}$)
Calculated as:
Leakage emissions due to fugitive upstream CH_4 emissions are calculated as per equation 6 of AM0029:

Quantity of natural gas combusted in the project plant (FC_y): 685,321,088 SCM
Average net calorific value of natural gas ($NCV_{NG,y}$): 8570 kcal/SCM
Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in t CH_4 per GJ fuel supplied to final consumers
($EF_{NG, upstream,CH4}$): 296 t CH_4/ PJ

Electricity generated in the project plant ($EG_{PJ,y}$) : 3492 MU
Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in t CH_4 per MWh electricity generation in the project plant ($EF_{BL, upstream, CH4}$) : 16.11 t CO_2e/MU

= [(685,321,088 * 8570* 1000 * 4.186 * 10^{-15} * 296)* 21 – (3492 * 15.72)] = **97,909** tCO_2e.

3B) Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re -gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$)

In the current context LNG is not being used in the project activity hence, $LE_{LNG,CO2,y} = 0$.
In future, if the LNG will be used, the leakage will be calculated as described below:

Calculated as per the methodology, AM0029
Quantity of natural gas combusted in the project plant ($FC_{LNG\ y}$) (For CO_2 emissions from LNG):
~~Q~~0 SCM
Calorific Value of Natural Gas: 8570 kcal/ SCM
Emission factor for upstream CO_2 emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($EF_{CO2,\ upstream,LNG}$) : 6 t CO_2/ TJ

Based on the above, the estimated Leakage emissions due to fossil fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) will be:

$LE_{LNG,CO2,y}$ = ~~Q~~0 SCM * 8570 Kcal/ SCM * 4.186 * 10^{-9} * 6 t CO_2/ TJ
= 0 ~~$LE_{LNG,CO2,y}$~~ t CO_2

4. Emissions Reduction (ER_y)

According to the approved Methodology AM0029 Version 3:

$$ERy = BEy – PEy – LEy$$

Where:
ERy : emissions reductions in year y (t CO_2e)
BEy : emissions in the baseline scenario in year y (t CO_2e)
PEy : emissions in the project scenario in year y (t CO_2e)
LEy : leakage in year y (t CO_2e)

ERy = 2,770,562– 1,379,231 – 97,909 = 1,293,422tCO_2e

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

Year	**Estimation of Project activity emissions (tonnes of CO_2e)**	**Estimation of baseline emissions (tonnes of CO_2e)**	**Estimation of leakage (tonnes of CO_2e)**	**Estimation of overall emission reductions (tonnes of CO_2e)**
2011~~0~~	1,379,231	2,770,562	97,909	1,293,422
2012~~1~~	1,379,231	2,770,562	97,909	1,293,422
2013~~2~~	1,379,231	2,770,562	97,909	1,293,422
2014~~3~~	1,379,231	2,770,562	97,909	1,293,422
2015~~4~~	1,379,231	2,770,562	97,909	1,293,422

2016~~5~~	1,379,231	2,770,562	97,909	1,293,422
2017~~6~~	1,379,231	2,770,562	97,909	1,293,422
2018~~7~~	1,379,231	2,770,562	97,909	1,293,422
2019~~8~~	1,379,231	2,770,562	97,909	1,293,422
2020~~19~~	1,379,231	2,770,562	97,909	1,293,422
Total (tonnes of CO_2e)	**13,792,310**	**27,705,620**	**979,090**	**12,934,220**

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

Monitoring methodology and monitoring plan for the project activity has been prepared using the guidelines provided in Approved monitoring methodology AM0029, V- 03, EB 39.

Title -Grid Connected Electricity Generation Plants using Non-Renewable and Less GHG Intensive Fuel.

As per the methodology, the baseline emissions will be monitored per "Tool to calculate emission factor for an electricity system", if and as applicable. For the project emissions, a record of (1) Annual fuel consumption in project activity (2) Net Calorific Value of the fuel used in the project activity (3) Fuel emission factors for fuel used in the project activity.

The applicability of this methodology to the proposed CDM project activity has been discussed in Section B.2 above.

All the data monitored for the estimation of project, baseline and leakage emissions for verification and issuance will be kept for two years after the end of the crediting period or the last issuance of CERs for this project activity, whichever occurs later.

As part of monitoring leakage, the existing user of natural gas for electricity generation will be monitored through out the crediting period for non-diversion. Similarly, to check whether the future capacity addition is prohibited due to the project activity power plant, future gas allocations to power plants, start of construction and start of operations of new NG based power plants will be monitored for about double the capacity of the project activity power plant. In each monitoring period, if all existing users operated their power plants using NG, it will be concluded as non-diversion. Leakage will be only applied if these users operated using any other fuels than NG. The future capacity addition will be monitored only for next 900 MW (about double the capacity of the project activity power plant) capacity gets allocation of gas or starts construction.

B.7.1 Data and parameters monitored:

Data / Parameter:	**$EG_{PJ,y}$**
Data unit:	~~G~~MWh
Description:	Electricity ~~Generated during~~exported to the grid by the project activity ~~per annum~~in year y
Source of data to be used:	The monthly joint meter readings (JMR) taken from the ~~cumulative~~ tariff meters (4 numbers, one main and one check on each of the two transmission lines) present in the Tariff metering room present in the switch yard.~~ The readings are stored in power plant log book.~~
Value of data	3,492,000

Description of measurement methods and procedures to be applied:	The data represents the net electricity export from the project activity power plant measured by the ~~Cumulative Energy~~tariff Meters. These four meters ~~is~~ ~~a~~are 3 phase 4 wire meters and of an accuracy of 0.2S class. ~~This represents the summation of the readings measured by the energy meter line 1 and energy meter line 2. This energy meter is present in the Swi~~tch Yard, Tariff metering room. The readings are also taken manually every day at 00 hrs. ~~The readings are stored in the power plant electricity generation log book.~~ The readings are taken by the shift engineers and are cross checked by the ~~site main controller~~shift incharge and are recorded in the log book. These meters will read both export and import values. The net export will be calculated from readings of these meters (total export – total import). The total net export from power plant will be calculated by summation of the readings measured by the main tariff meters of line-1 and line-2.
QA/QC procedures to be applied:	~~The data measured by the cumulative meter will read both import and export of electricity. The net export of electricity is cross checked with the summation of the electricity measured by the energy meter line 1 and energy meter line 2.~~ The calibration of the instruments would be done ~~every 6 months~~annually[55] at CPRI, Hyderabad/ ETDC (Hyderabad/Chennai/ Bangalore etc.) or alternatively at NABL accredited third party fixed/ mobile laboratory approved by AP Power Coordination Committee (APPCC). The meters will be replaced by pre-calibrated meters and used meters will be sent for calibration. ~~The readings are taken by the shift engineers and are cross checked by the site main controller and are recorded in the log book.~~ Both the transmission lines have individual check meters by the power purchaser (APDISCOMS through APTransco~~EPDCL – Andhra Pradesh Eastern Power Distribution Company Limited – part of earlier existing company APTransco~~) and readings are given in JMR. Check meters will be calibrated by APTransco/ APDISCOMs as per their procedures (and are not part of this monitoring). The readings of JMR will be cross checked with the invoice sent to power purchaser and lower of the two will be used for the calculation of emission reductions.
Any comment:	Electricity generation is estimated from installed capacity and PLF as per EPC i.e. 469 x 24 x 365 x 85%/ 1000 = 3,492 GWh

Data / Parameter:	**$EF_{BL,CO2,y}$**
Data unit:	tCO_2/MWh
Description:	baseline CO_2 emission factor – build margin of southern grid

[55] As per PPA, calibration is required once in six months. The PP maintains 2 meters each (main and check) for each of the two transmission lines (line 1 and line 2), and a rolling stock of meters to keep pre-calibrated meters ready for replacement within six months. The meters are taken to Hyderabad/ Chennai/ Bangalore etc. and take few weeks for completeing process, thus each meter is not exactly calibrated within six months, but definitely a pre-calibrated meter is installed for use and taken out within six months. The installation and removal of meters on transmission lines is recorder in PP's internal documents. To avoid use of these multiple documents, annual calibration records will be shown for each used meter during monitoring period as the calibration validity as per existing calibration norms is one year.

Source of data to be used:	Calculated as per the monitoring methodology AM0029
Value of data	0.7634
Description of measurement methods and procedures to be applied:	Calculated as per monitoring methodology AM0029 As the option 1 - build margin is chosen, this parameter will monitored ex-post and based on latest available database published from the CEA (CO_2 Baseline database for the Indian power sector).
QA/QC procedures to be applied:	The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'. Thus, no QA/QC is required.
Any comment:	this value will be monitored ex-post as required by the monitoring methodology AM0029 and archived electronically for crediting period + 2 years. As the Option I is found to be lowest emission factor among three options, during monitoring other two emission factors will not be calculated.

Data / Parameter:	**~~Q~~FC**$_{NG}$
Data unit:	m^3~~SCM~~
Description:	Quantity of NG consumed in the project activity
Source of data to be used:	~~The readings are recorded manually at 00 hrs and are stored in the power plant log book.~~ Gas supplier's fuel flow meter reading at project boundary given as fortnightly joint ticket. GAIL has a gas supply terminal near project plant, included in the project boundary, where gas quantity is metered and displayed in SCM i.e. standard cubic meters (at standard temperature and pressure). Presently there are two gas metering lines (line A and line B) and both have separate metering (flow meters). At any time, any or both lines can be operated. If both lines operate on any day, the sum of these two line meters will be used to get total gas consumption. PP and GAIL representative also sign a daily joint ticket. If any data not covered by fortnightly joint ticket is required, daily joint ticket will be used.
Value of data	685,321,088
Description of measurement methods and procedures to be applied:	The quantity of Natural Gas is measured by the gas flow meter which would be installed by GAIL at their terminal. The flow meter by GAIL is a volumetric flow meter and gives reading directly in m^3. This is a Daniel make 4-path gas flow meter[56] based on ultrasound and does not require calibration[57]. The device also uses pressure transducer, temperature transducer and flow computer for mass flow calculation and these transducers will be calibr~~eu~~ated annually. The gas consumed is also continuously measured (cross check) by PP using inbuilt system in the gas turbine controls (Alstom GT 13E2/ ABB control system~~make – same mass flow is used for GT functioning~~). Gas flow mea~~t~~surement~~r~~[58] of PP ~~is a mass flow meter and~~ gives readings kg/s in DCS~~and density of gas is also continuously displayed using same meter in~~

[56] http://www2.emersonprocess.com/en-us/brands/daniel/Flow/ultrasonics/Pages/Ultrasonic-Series-3400.aspx

[57] http://igs.nigc.ir/igs/ARTIC/NG-31.PDF

[58] Alstom GT13E2 Gas turbine control system (EGATROL-8) has an in-built mechanism to calculate Gas mass flow requirement to the turbine. This calculation is done in turbine closed loop controllers and is based on the real time parameters of the certain process measurements such as Gas Pressure, differential pressure across gas control valves

	~~the DCS~~. Thus, using this mass flow and density, PP gets data in m^3 to cross check main meter reading from GAIL. Higher of the main and check meter readings will be used for the emission reduction calculations. ~~PP's gas flow meter = 5%~~
QA/QC procedures to be applied:	The quantity of natural gas is cross checked with ~~the invoices that are obtained from the GAIL and it is also tallied with~~ the quantity of Natural Gas measured using~~by~~ the gas flow ~~meter that is installed~~controls by the project proponent ~~for internal purposes~~. GAIL meter is out of PP's control and is a factory calibrated as per their standards. The temperature transmitter (TT) and pressure transmitter (PT) associated with gas flow meter will be calibrated jointly by gas supplier and PP quarterly). TT – Accuracy and calibration frequency = ± 0.2%, once in a quarter PT - Accuracy and calibration frequency = ± 0.075%, once in a quarter ~~PP's gas flow meter has accuracy of ±0.35 and will be calibrated annually.~~ ~~The meter installed by GAIL will be calibrated according to the standard procedures~~
Any comment:	Presently, this value is ~~E~~estimated based on design electricity generation, station heat rate and fuel NCV

Data / Parameter:	**FC_{LNG}**
Data unit:	m^3
Description:	Quantity of LNG consumed in the project activity[59]
Source of data to be used:	Gas supplier's fuel flow meter reading at project boundary given as fortnightly joint ticket. GAIL has a gas supply terminal near project plant, included in the project boundary, where gas quantity is metered and displayed in SCM i.e. standard cubic meters (at standard temperature and pressure). Presently there are two gas metering lines (line A and line B) and both have separate metering (flow meters). At any time, any or both lines can be operated. If both lines operate on any day, the sum of these two line meters will be used to get total gas consumption. PP and GAIL representative also sign a daily joint ticket. If any data not covered by fortnightly joint ticket is required, daily joint ticket will be used.
Value of data	0
Description of measurement methods and procedures to be applied:	The quantity of Natural Gas is measured by the gas flow meter which would be installed by GAIL at their terminal. The flow meter by GAIL is a volumetric flow meter and gives reading directly in m^3. This is a Daniel make 4-path gas flow meter[60] based on ultrasound and does not require calibration[61]. The device also uses pressure transducer, temperature transducer and flow computer for mass flow calculation and these transducers will be calibrated annually.

and Gas temperature. The Calculated Gas Flow readings are in kg/S only and is displayed automatically and logged in to Egatrol-8 Historian server.

[59] PP received LNG at project boundary in gas form. LNG is received at any of the LNG terminals in the country and regassified. Then this regassified LNG is pumped in the NG grid and supplied to end users. Thus, same meters as that for the NG are used for LNG metering as well.

[60] http://www2.emersonprocess.com/en-us/brands/daniel/Flow/ultrasonics/Pages/Ultrasonic-Series-3400.aspx

[61] http://igs.nigc.ir/igs/ARTIC/NG-31.PDF

	The gas consumed is also continuously measured (cross check) by PP using inbuilt system in the gas turbine controls (Alstom GT 13E2/ ABB control system). Gas flow measurement[62] of PP gives readings kg/s in DCS. Thus, using this mass flow and density, PP gets data in m^3 to cross check main meter reading from GAIL. Higher of the main and check meter readings will be used for the emission reduction calculations.
QA/QC procedures to be applied:	The quantity of natural gas is cross checked with the quantity of Natural Gas measured using the gas flow controls by the project proponent. GAIL meter is out of PP's control and is a factory calibrated as per their standards. The temperature transmitter (TT) and pressure transmitter (PT) associated with gas flow meter will be calibrated jointly by gas supplier and PP quarterly). TT – Accuracy and calibration frequency = ± 0.2%, once in a quarter PT - Accuracy and calibration frequency = ± 0.075%, once in a quarter
Any comment:	Presently, this value is estimated based on design electricity generation, station heat rate and fuel NCV

Data / Parameter:	**NCV_{NG}**
Data unit:	GJ/m^3~~kcal/ SCM~~
Description:	Net Calorific Value of Natural Gas
Source of data to be used:	~~Invoice~~ fortnightly (or daily) joint ticket~~from~~ signed by the gas supplier
Value of data	~~8570~~0.03587
Description of measurement methods and procedures to be applied:	The Supplier provides the value of the NCV in the daily/ fortnightly joint ticket~~invoice that is being~~ given to the project proponent. The NCV is measured by the Gas ~~calorimeter~~ chromatograph that would be installed by GAIL at their terminal.
QA/QC procedures to be applied:	~~The NCV of natural gas is cross checked with the invoices that are obtained from the GAIL and it is also tallied with the NCV measured by the Gas calorimeter calculator which is installed by the project proponent for internal purposes. The meter installed by GAIL will be calibrated according to the standard procedures.~~ The net calorific value of natural gas consumed would be provided by supplier. This is done on continuous basis using a Gas Chromatograph installed by GAIL. The weighted average of NCV for the monitoring period will be calculated using daily joint ticket taken by GAIL and PP. Cross check: The monitoring methodology does not require cross checking this paramater
Any comment:	The supplier invoice presently does not give NCV and mentions GCV. Thus NCV will be taken from the daily / fortnightly joint tickets taken by GAIL and PP. For ex-ante estimation, calculated based on 8,570 kcal/SCM value as used in

[62] Alstom GT13E2 Gas turbine control system (EGATROL-8) has an in-built mechanism to calculate Gas mass flow requirement to the turbine. This calculation is done in turbine closed loop controllers and is based on the real time parameters of the certain process measurements such as Gas Pressure, differential pressure across gas control valves and Gas temperature. The Calculated Gas Flow readings are in Kg/S only and is displayed automatically and logged in to Egatrol-8 Historian server.

	the investment analysis NCV = 8,570 x 4.186/10^6 = 0.03587 GJ/m^3

Data / Parameter:	**NCV_{LNG}**
Data unit:	GJ/m^3
Description:	Net Calorific Value of LNG
Source of data to be used:	fortnightly (or daily) joint ticket signed by the gas supplier OR invoice from supplier
Value of data	0
Description of measurement methods and procedures to be applied:	The Supplier provides the value of the NCV in the daily/ fortnightly joint ticket given to the project proponent. The NCV is measured by the Gas chromatograph that would be installed by GAIL at their terminal.
QA/QC procedures to be applied:	The net calorific value of natural gas consumed would be provided by supplier. This is done on continuous basis using a Gas Chromatograph. The weighted average of NCV for the monitoring period will be calculated using daily joint ticket taken by GAIL and PP.
Any comment:	The supplier invoice presently does not give NCV and mentions GCV. Thus NCV will be taken from the daily joint ticket taken by GAIL and PP. For ex-ante estimation, calculated based on 8,570 kcal/SCM value as used in the investment analysis

Data / Parameter:	$COEF_{f,y}$
Data unit:	tCO_2/ m^3
Description:	Calculation of CO_2 Emission Co-efficient of natural gas
Source of data to be used:	Calculated
Value of data	0.0020
Description of measurement methods and procedures to be applied:	Calculated with formula given in applicable methodology AM0029 $COEF_{f,y} = \Sigma NCV_{f,y} * EF_{CO2,f,y} * OXID_f$
QA/QC procedures to be applied:	None as accepted under applicable methodology AM0029
Any comment:	The values of $EF_{CO2,f,y}$ and $OXID_f$ will be used as per IPCC Guidelines and NCV as monitored in the monitoring plan as actual 8,570 kcal/SCM * 4.186 * 10^{-9} * 56.1 t CO_2 / TJ * 1 = 0.0020 tCO_2/ m^3

Data / Parameter:	$Oxid_{NG}$
Data unit:	Unit less factor
Description:	Oxidation Factor of NG
Source of data to be used:	IPCC Default Value
Value of data	1
Description of measurement methods	IPCC default value used in absence of country specific data (Reference - Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas

and procedures to be applied:	Inventories)
QA/QC procedures to be applied:	IPCC Default Value, so does not require QC
Any comment:	Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories – latest available now. If the report is updated in future, the same will be used.

Data / Parameter:	$EF_{BL,\ Upstream,CH4}$
Data unit:	t CH_4/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity in terms of ton of methane per MWh
Source of data to be used:	Calculated as: $$EF_{BL,upstream,CH4} = \frac{\sum_j FF_{j,k} \cdot EF_{k,upstream,CH4}}{\sum_j EG_j}$$ $\Sigma FF_{j,k}$: Refer to "Fuel consumed by power sources included in BM from latest CEA or equivalent database for Indian Power Sector $EF_{k,upstream,CH4}$: Table 2 of AM0029. ΣEG_j : Refer to "Electricity delivered to grid by power sources included in BM" latest CEA or equivalent database for Indian Power Sector
Value of data	15.72 tonnes CO_2/MU
Description of measurement methods and procedures to be applied:	Wherever necessary default values suggested in the approved methodology AM0029 are used in the formula above to arrive at the above value. e.g. Fugitive methane emission factor for coal production = 0.8 (for surface mining, as most of the coal production in India comes from open pit mines contributing over 81% of the total production[63])
QA/QC procedures to be applied:	This is a calculated value from monitored parameters, thus does not require separate QC
Any comment:	Calculated using CEA CO_2 Baseline Database version 5.0

Data / Parameter:	$EF_{CO2,NG,y}$
Data unit:	$kgCO_2e/TJ$
Description:	Emission Factor of Natural Gas
Source of data to be used:	Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories
Value of data	56,100
Description of measurement methods and procedures to be applied:	In absence of country specific data; IPCC default value used as recommended in methodology.
QA/QC procedures to be applied:	IPCC Default Value, so does not require QC

[63] http://www.mbendi.co.za/indy/ming/coal/as/in/p0005.htm

Any comment:	Table 1.4, Chapter 1, Volume 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories – latest available now. If the report is updated in future, the same will be used.

~~Data / Parameter:~~	~~$EF_{CO2,coal,y}$~~
~~Data unit:~~	~~kg CO_2e/TJ~~
~~Description:~~	~~Emission Factor of Coal~~
~~Source of data to be used:~~	~~CEA CO_2 Baseline Database, version 05~~
~~Value of data~~	~~95,800~~
~~Description of measurement methods and procedures to be applied:~~	~~The value is taken from the database developed by Central Electricity Authority (CO_2 Baseline database for the Indian power sector, Version 5.0). The database is Government of India's official publication based on the 'Tool to calculate the emission factor for an electricity system'.~~
~~QA/QC procedures to be applied:~~	~~Not applicable as this is a default value~~
~~Any comment:~~	~~-As the database/ version of reference will be updated, latest version at the start verification will be used~~

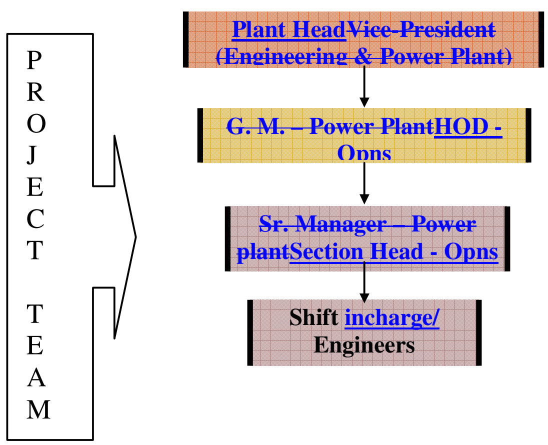
~~Data / Parameter:~~	~~$EF_{NG, Upstream,CH4}$~~
~~Data unit:~~	~~t CH_4/GJ~~
~~Description:~~	~~Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution, and, in the case of LNG, liquefaction, transportation, re-gasification and compression into a transmission or distribution system, in tCH_4 per GJ fuel supplied to final consumers.~~
~~Source of data to be used:~~	~~Table 2, page 8 of the approved methodology AM0029~~
~~Value of data~~	~~296 t CH_4/ PJ~~
~~Description of measurement methods and procedures to be applied:~~	~~In the absence of country specific values, the reference value from the approved methodology AM0029 is used as a conservative estimate.~~
~~QA/QC procedures to be applied:~~	~~This is a default value given in the monitoring methodology, so does not required QC~~
~~Any comment:~~	~~-~~

Data / Parameter:	**PEy**
Data unit:	tCO_2
Description:	Project emission due to combustion of fuel
Source of data to be used:	Calculated under project activity
Value of data	1,379,231
Description of measurement methods and procedures to be	~~Please refer to Section B.6.3 of the PDD for step wise calculation procedure~~The parameter will be calculated based on the stepwise procedure discussed in the Section B.6.3 above

applied:	
QA/QC procedures to be applied:	Not applicable as it is a calculated value
Any comment:	This value will be calculated ex-post in the monitoring period.

B.7.2 Description of the monitoring plan:

The project activity is operated and managed by the project proponent through GVK Power and Infrastructure Limited. The individual plants record data related to their respective project activity. The natural gas based power project abides and will abide by all regulatory and statutory requirements as prescribed under the state and central laws and regulations. A CDM project team has been established at the plant site. The project team is entrusted with the responsibility of storing, recording the data related to the project activity. The project team is also responsible for calculation of actual creditable emission reduction in the most transparent and relevant manner. Installed meters are calibrated according to the maintenance schedule programmed at the start of the operation and recalibrated according to the plant's performance requirement. All the monitoring data will be stored, recorded and kept under safe custody of the Project Executor and Head (Power Plant and Utilities) at the plant site for the full crediting period + 2 years. Also any change within the project boundary, such as change in spare and or equipments will be recorded and any change in the emission reduction due to such alteration will also be studied and recorded.



Designation	Responsibilities
~~Vice-President (Engineering & Power Plant)~~Plant head	• Registration • Project Execution
~~G. M. – Power Plant~~HOD - Operations	• Operation • Verification of data • Inspection of data whenever necessary to independently check the authenticity of data and take corrective actions wherever required. • Storage of data
~~Sr. Manager – Power Plant~~ Section Head - Operations	• Operation, Monitoring and Verification of Data • Data Recording

	• Storage of data
Shift incharge/ Engineers ~~and Operators~~ ~~(Operation and Maintenance)~~	• Operation and Maintenance • Storage of data • Data Recording • Data Collection • Archiving of data • Observation, Monitoring

Emergency plan:

The electricity meter (the main meter owned by PP) will be calibrated annually. In case, both the main and check meters have shown error more than the limit prescribed in the class, both the meters will be taken for the calibration and correction will be applied to the electricity generation recorded by the main meter. If main meter fails to record for some duration, then check meter readings will be used for the calculation of emission reductions.

Monitoring of gas consumed in the project activity and NCV

Gas consumed is measured by GAIL's fuel flow meter reading (main meter) at project boundary. GAIL has a gas supply terminal near project plant, included in the project boundary, where gas quantity is metered and displayed in SCM i.e. standard cubic meters (at standard temperature and pressure).
Presently there are two gas metering lines and both have separate metering. At any time, any or both lines can be operated. If both lines operate for any period, the sum of these two line meters will be used to get total gas consumption. There is a joint ticket signed by GAIL and PP's representative based on this reading, this will be used as source of data for gas consumed.

Gas consumption will be cross-verified by PP using GT's inbuilt mass flow indicator. The flow meter by GAIL is a volumetric flow meter and gives reading directly in m^3. Gas flow measurement~~meter~~ of PP is a mass flow measurement~~er~~ and gives~~n~~ readings kg/s and density of gas is also continuously displayed ~~using same meter~~ in the DCS. Thus, using this mass flow and density, PP gets data in m^3 to cross check. The net calorific value of natural gas consumed would be provided by supplier. This is done on continuous basis using a Gas Chromatograph. The weighted average of NCV for the monitoring period will be calculated using daily joint ticket taken by GAIL and PP.

As the project activity ~~registration~~ crediting period may not coincide with the JMR date (both monitoring period start and -the end), in that case, (1) the net electricity export for this period will be ~~monitored from the check meter/ DCS readings from the PP's monitoring system~~taken from daily manual tariff meter readings taken by shift incharge and (2) gas quantity and NCV will be taken from daily joint ticket~~.~~ OR (2) the crediting period start will be taken from the subsequent JMR date after the registration date[64]'.

Internal Audit:
An internal audit team shall be constituted for verifying and auditing of the data recorded and archived with respect to the registered PDD and the monitoring plan. The audit team shall also verify and audit the calibration plan and calibration record of the instruments with respect to the registered PDD and the monitoring plan. The audit team shall meet once in three months (quarterly) to verify and audit the data

[64] This sentence is not applicable at the time of RMP request, only maintained from registered PDD for clarity

collected, the process followed and the quality control and assurance measures. They shall report any non-conformity to the Plant Head, who shall take appropriate steps to rectify the non-conformity. The internal audit team shall also certify the annual consolidated data for the verification of CER.

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

30/05/2008

GVK Gautami Power Ltd. (and their CDM advisors General Carbon) is a project participant and the contact details are given in the Annex 1.

SECTION C. Duration of the project activity / crediting period

C.1 Duration of the project activity:

C.1.1. Starting date of the project activity:

01/07/2004

The starting date of the project date is taken as 01/07/2004, which is the date of notice to proceed for the project activity. This was date when the project proponent committed to the expenditures for the project activity with financial closure and notice to proceed to the EPC Contractor (with first instalment).

As per the CDM Guidance (Glossary of CDM terms, Ver. 04, pg. 29), the start date shall be considered to be the date on which the project participant has committed to expenditures related to the implementation or related to the construction of the project activity. Minor pre-project expenses, e.g. the contracting of services /payment of fees for feasibility studies or preliminary surveys, should not be considered in the determination of the start date as they do not necessarily indicate the commencement of implementation of the project. EB 41, Meeting Report, para 67).

Thus, the signing of contracts like PPA, EPC do not necessarily stand as financial commitments and can be revoked subject to some financial liability in some cases, however insignificant compared to the total project cost. Thus, the chosen start date is appropriate as per the CDM Guidance.

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

15 years 0 months[65]

[65] Depreciation Norms for Generating Companies; Ministry of Power, New Delhi; Notification, 29/03/1994 http://powermin.nic.in/acts_notification/generating_companies.htm

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

C.2.1. Renewable crediting period

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

NA

C.2.1.2. Length of the first crediting period:

NA

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

01/08/2011 or a date not earlier than the date of registration

C.2.2.2. Length:

10 years 0 months

SECTION D. Environmental impacts

>>

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

An Environmental Impact assessment for the project activity has been conducted by SGS India Ltd., Environmental Services Secunderabad in the month of November 2000. The environment management plan is prepared to minimize the potential environmental impacts arising out of the proposed project activity and for plant operation to coexist satisfactorily with its surrounding environment by reducing its adverse impacts.

The proposed project activity would create impacts on environment in two distinct phases:

- During the construction phase which may be regarded as temporary or short term
- During the operation phase which would have long term effects

The plant is located in a notified industrial area and the proposed plant will run on natural gas (a clean fuel). Thus it is ensured that there are no major negative impacts envisaged on the air quality, water environment and land environment of the surrounding region. Moreover the plant authorities have taken necessary care to see that all statutory regulations existing in the country are followed.

The following expected impact may occur as a result of the project activity during the construction phase:

1. Land use

The construction of the Combined Cycle Power Plant would bring in certain immediate changes in the land use pattern of the proposed area as well as in the vicinity. Construction activities would attract a sizable labour population and the influx of the population is likely to be associated with construction of labour colony within the plant premises. This would be temporary in the case of the proposed project activity as the gestation period is very small.

2. Air environment
Light negative impact on ambient air quality is envisaged due to the emission of suspended particles during the construction phase. The concentration of NOx and CO might also increase due to the vehicular movement. To mitigate these impacts regular sprinkling of water will be done at the construction site.
3. Noise environment
The major sources contributing to the noise pollution during the construction phase are vehicular traffic and construction equipment like dozers, scrappers, concrete mixers, cranes, generators etc. use of proper personal protective equipment will mitigate any significant impact of the noise generated by such equipment.
4. Terrestrial Ecology
The initial construction works at the project site involves no land clearance, cutting of trees, filing and levelling as the land is barren. So construction activity will not result in any loss of either vegetation or potential agricultural productive land.

The following impact may be expected to occur as a result of the operation of the project activity:
- *Soil*

The impact of the Natural Gas based power plant on soil characteristics is insignificant as compared to the impact of coal based power plant projects. Most of the impacts are restricted to the construction phase which will get stabilized during the operational phase.
- *Air Quality*

Natural Gas based power plant will have NOx as the major air pollutant and SO_2. The emissions of the particulate matter will be insignificant. Adequate stacks will be provided to disperse the pollutants. The EIA studies show that due the good dispersion of the pollutants, it will not affect the ground level concentrations of the air.
- *Water Quality*

The ground water is not used for the operation of the project activity, so it will not be affected. Other probable source may be due to land application of the effluent water. However, there is a good waste water treatment scheme and the discharge water will meet the regulation of pollution control board. So, the project activity will not affect the water quality.

- *Noise environment*

The major sources contributing to the noise pollution from the power plant are gas turbines, compressors, steam turbine, inlet and exhaust system. During the operation there would be an increase in the ambient noise level and may affect occupational health. However, the noise level is within prescribed limit by OSHA i.e. 90 dB(A) for 8 hours. As the other community settlements are beyond the 1.5 km radius, there will be no significant impact.
- *Ecology and biodiversity*

The activities of the power plant operations such as stack emission, waste water discharges and solid waste disposals have a potential to affect the ecology and biodiversity of this region.

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

The significant environmental impacts of the project activity along with the measures taken to mitigate the impacts and the conclusions are enumerated in Appendix A[66].
The mitigation measures that have been adopted are elaborated below

A. Management during construction phase

The impact during the construction phase on the environment would be basically of transient nature and are expected to reduce gradually on completion of the construction activities. In order to mitigate them following measures are proposed:

1. Designation and demarcation of sites for construction camps and ensuring due provision of necessary infrastructural services.

   a. During excavation and transportation over unmetalled roads near the proposed plant site, there is a scope of local dust emissions. Frequent water sprinkling in the vicinity of the construction activity would be done and it would be continued even after the completion of the plant construction, as there is scope for heavy truck mobility. The industry should make provision for water sprinklers.
   b. Since there is likelihood of fugitive dust from the construction activity, material handling and from the truck movement in the premises of the proposed plant, the industry will go for green belt plantation programme along the boundaries of the proposed plant site.
   c. The construction site will be provided with sufficient and suitable sanitary facilities for workers to have proper standards of hygiene. These facilities would be connected to septic tank and maintained to ensure minimum environmental impact.
   d. Though the noise effect on the nearest inhabitants due to construction activity will be negligible onsite workers working in the vicinity of high noise will be provided with noise protection devices. Noise prone activities will be restricted to the extent possible during night particularly during the period 10:00 PM to 6:00 AM in order to have minimum environmental impact.
   e. It will be ensured that both gasoline and diesel powered construction vehicles are properly maintained to minimize smoke in the exhaust emissions. The vehicle maintenance area will be located in such a manner to prevent contamination of surface and ground water sources by accidental spillages of oil. Unauthorized dumping of waste oil will be prohibited.
   f. As soon as construction is over, the surplus earth will be utilized to fill up low lying areas, the rubbish will be cleared and all un-built surfaces reinstated. Appropriate vegetation will be planned and all such areas will be landscaped. Hazardous materials (e.g. acids, paints, explosives) will be stored in proper and designated areas.

2. To prevent unauthorized felling of trees by construction workers for their fuel needs, it will be ensured that the contractor provides fuel to the construction workers

B. Management during the operational phase

   a. Air pollution control system: The air pollution control measures proposed for the project are described below:
      i. 70 m tall stack will be provided to ensure proper dispersion of pollutants
      ii. Appropriate system to control NOx emissions to 75 ppm will be provided
      iii. Green belt development in and around the plant premises will be undertaken

[66] The copy of the detailed EIA report will be made available during the time of validation.

iv. The proposed air pollution control equipment will be installed prior to commissioning of the plant
v. Monitoring of stack emissions for NOx and SO_2 will be carried out regularly to meet all statutory requirements
vi. All the internal roads will be asphalted to reduce the fugitive dust due to vehicle movement

b. Water pollution control system: The waste water will be originating from cooling system, plant service water system, filter backwash and sanitary effluents from plant. All these waste will be treated and discharged on the land to be utilized for green belt through a central monitoring basin.

Following effluent treatment and disposal systems are proposed to be installed:

i. Minimize quantity of effluents through reuse to the extent possible;
ii. Treatment of the DM plant waste through neutralization;
iii. Provision of oil separators

Effluent monitoring instruments namely pH meter, flow meter, etc. will be provided in the effluent discharge line. Flow integrators will be provided both at the plant intake and discharge point at central effluent holding pond.

Apart from the proposed treatment schemes, some additional measures that will be undertaken are given here under:

i. Minimize quality of effluents through reuse to the maximum extent feasible;
ii. The treatment scheme proposed should be constructed before the commissioning of the plant
iii. Sedimentation tanks will be cleaned regularly in order to avoid clogging. Sludge should be removed regularly and sufficient time should be given for proper settling of solids
iv. The treatment units viz., Sewage Treatment Plant will be operated regularly
v. Monthly effluent samples will be collected and analysed at the inlet and outlet of the treatment plants to ascertain the efficiency of the treatment plants and to meet the statutory requirements.

c. Solid waste management plan: Solid wastes generated from the plant are basically from sedimentation tanks and sewage treatment plants. The solid waste does not contain any toxic matter and it is safe to dispose off on land.

The suitable landfill area should be identified taking into consideration permeability of soil, distance from population area, etc. the collection, transport and disposal of solid wastes from different parts of the plant to the disposal area should be through sanitation contract package.

d. Noise level management: The predominant noise levels will be confined to the work zones in the plant. The noise levels at the entire sources will not exceed 85 dB(A). Community noise levels are not likely to be affected because of proposed vegetation and attenuation due to the physical barriers.

i. The use of damping materials such as thin rubber/lead sheet for wrapping the work places like turbine halls, compressor rooms, DG sets, etc.;
ii. Shock absorbing techniques would be adopted to reduce impact;

iii. Efficient techniques for noise associated with high fluid velocities and turbulence would be used;
iv. All the openings like covers, partitions would be acoustically sealed;
v. Inlet and outlet mufflers would be provided which are easy to design and construct;
vi. Reflected noise would be reduced by the use of absorbing material on roofs walls and floors;
vii. Ear plugs would be provided to the workers, and it should be enforced to be used by the workers;
viii. Provision of the separate cabins for workers and operators
ix. The industrial compound would be thickly vegetated with species of rich canopy

e. Measures for improvement of ecology
   i. Clearing of existing vegetation would be kept to minimum
   ii. Plantation programme would be undertaken in all areas. This should include plantation in the proposed plant premises, along the internal and external roads

SECTION E. Stakeholders' comments

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

The important local stakeholders were identified as the locals residing in the neighbouring villages, local health officer, staff of neighbouring college, officials of state electricity board and pollution control board. Most of these are residents of the neighbouring areas in the project site and are likely to be affected, if at all. All the identified stakeholders were communicated by written invitation 15 days in advance before the meeting.

The meeting was held in the project activity premises on 30/11/2007. A total 25 people attended the meeting and the minutes of the meeting signed by the chairman will be made available during the time of validation.

The project activity was explained to the gathering and a brief presentation on climate change and the Clean Development Mechanism was made. The role of the project activity in the mitigation of climate change and local sociological benefits were explained. Then queries were invited from the local stakeholders. The summary of comments and the replies are presented in the following section. The stakeholders were given further 15 days time to contact project proponents for any further queries.

E.2. Summary of the comments received:

The details regarding the queries expressed by the members and the clarifications by PP are as follows.

S.No	Name of the Member	Doubt Expressed	Clarification.
1	Sri. K.Jagannadham	The project may pose health and skin problems.	As this project depends on clean and pure natural gas there is no scope for any health and skin problems.
2	Sri. G.Venkata Rao	Is there any danger due to the leakage of natural	There is no need to store the natural gas as it is arranged to supply as per the need to the project. In

		gas/liquid fuel?	case there is any leakage in liquid fuel, necessary arrangements are made to store such fuel to avert any danger.
3	Sri. Mohanty	(a)What are the safety arrangements that are maintained to face any accidents?	Necessary safety measures are taken after examining all possible safety arrangements that are required. Accordingly environmental impact and risk assessment reports have been prepared.
		(b)Whether necessary employment opportunities are created to the people of surrounding villages?	Employment is provided as per the need to the residents of surrounding villages. Sri G. Venkata Rao, Honourable member has expressed his satisfaction in this aspect.
		(c)Whether any community facilities were provided to the residents of nearby villages?	Compound wall and stage is provided to the school building at Hussainpuram. Further it is assured by the Vice president/ General Manager of the plant that as soon as the production is started from the plant, some more facilities will be provided as per the need of the villagers.

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

The stakeholders were given clarification on the issues raised as above to their satisfaction by providing relevant evidence of the project claims. There were no specific comments that required follow up action from CDM project activity point of view.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	GVK Gautami Power Limited, Hyderabad
Street/P.O.Box:	156-159, Sardar Patel Road
Building:	Paigah House
City:	Secunderabad
State/Region:	Andhra Pradesh
Postfix/ZIP:	500003
Country:	India
Telephone:	040-27902663
FAX:	040-27902665
E-Mail:	issac@gvk.com
URL:	http://www.gvk.com
Represented by:	Mr. A. Issac George
Title:	Director
Salutation:	Mr.
Last Name:	Anicattu
Middle Name:	Issac
First Name:	George
Department:	Finance
Mobile:	-
Direct FAX:	040-27902665
Direct tel:	040-66262103
Personal E-Mail:	aissacgeorge@yahoo.co.in

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

Public funding from Annex I countries and diversion of official development assistance (ODA), is not involved in this project activity. The project cost is met by the project proponents through own sources and in part by debt financing from banks.

Annex 3

BASELINE INFORMATION

Annex 4

MONITORING INFORMATION

The project proponent commits to contribute 2% of the revenue from the sale of CERs on realization, towards the social welfare activities and implement the following.

1. Conducting free medical camps in rural areas nearby
2. Medical assistance to weaker section of the society
3. Educational assistance for poor & handicap children in villages
4. Employment opportunities for physically handicapped
5. Assisting in improvement of infrastructure like lighting, water supply etc.
6. Participating in other social welfare scheme of own or conducted by others.
7. Funding to the Non Governmental Organization for the social welfare activities

These activities will be implemented either directly or by equivalent monetary donations to the organizations working in these areas and sectors. The allocation of committed money to be spent will be decided by the PP on realization of revenue from sale of CERs and as per the needs realized in future.

- - - - -

Appendix A

EIA of the project activity

Parameter	Potential impact without mitigating measures	Activities	Mitigating measures	Overall impact	Monitoring requirement	Responsible entities
Air environment	• Thermal pollution of air environment • Contribution to GLCs	• Exhaust gas from the gas turbines • Stack emission	• Installation of HRSG will enable reduction in temperature • Employ hybrid /dry low NOx burners	Long term negative	• Online stack gas monitors to be provided for carrying out flue gas monitoring on regular basis • Workspace environment to be monitored regularly for airborne pollutants • Ambient air quality monitoring in the adjoining villages as per MOEF guidelines to be carried out regularly	Management personnel of GVK Gautami Power Ltd. (GPL)
Noise environment	• Increase in ambient noise level • Impact on occupational health	• Movement of trucks transporting material and Operation of construction machineries, gas turbine, turbo generator, compressor, pumps, fans,	• Equipments in the power plant would be designed to have a total noise pollution as per the requirement of OSHA standards • Wearing ear muffs and ear plugs at the operational area • Intake and exhaust systems will be provided with silencers • 50m wide green belt to be		• Regular maintenance of all machinery and equipment to be undertaken so as to maintain noise levels within 85 dB at one meter distance at all sources • Workspace noise levels monitored regularly	Management personnel of GPL

		etc.	planted around the perimeter will attenuate the noise emitted by the various equipment in he plant • Acoustic enclosure would be provided to gas turbine generator			
Water environment	• Water balance • Impacts on ground water and hydrogeology • Withdrawal impacts on canal • Thermal pollution of water • Impact on aquatic life due to intake of water • Surface water quality	Disposal of the effluent water	• Effluent treatment scheme is evolved such that the treated effluent meets all necessary disposal standards. • • Treated effluent will be used for developing green cover around the plant site • Water is proposed to be drawn through sheltered basin so that it wont effect on the aquatic life • Closed cycle cooling system is adopted which requires comparatively less water requirement		• Well designed ETP proposed. Influent and effluent quality to be monitored regularly • Ground water quality monitoring to be carried out at regular intervals at plant site and eluru drain	Management personnel of GPL
Land environment	• Land use and terrestrial life • Soil quality • Agriculture • Forests and wild life	• Solid waste from the auxiliary units of plant • Application of the treated affluent on	• ETP sludge can be used as manure if found suitable • Raw water treatment plant sludge to be disposed off in controlled dumping sites within in the plant premises • Emphasis to be laid on green belt development and its maintenance		• Attention paid for development of green belt. Horticulturist to be employed to look after its development	Management personnel of GPL

		land	• Use of dry and fallow land for the plant operation			
Ecology and biodiversity	• Have a potential to affect the ecology of the area	• Stack emission, waste water discharges and solid waste disposals		Insignificant impact		Management personnel of GPL
Solid waste		• Sludge from the clarifier in water clarification plant			Sludge if possible will be used as manure.	Management personnel of GPL
Socio economic	Industry Infrastructure employment	• Investment of 14.5 billion rupees will have a significant impact on the industrial growth in the region as well as in the country • Help directly and indirectly in the development of civil infrastructure		Long term Positive impact		Management personnel of GPL

		• Direct employment to about 525 persons during the construction and 125 during the normal operation				

Socio economic benefit

1. Industry – the proposed project is with an investment of 14.5 billion rupees will have a significant impact on the industrial growth in the region as well as in the country
2. Infrastructure – the region around the proposed project site does not have very good infrastructural facilities. Near the project site the facilities for public transport, water supply, telecommunications, education, public wealth, etc., are inadequate. With the setting up of major industry like this, the region will naturally help directly and indirectly in the development of civil infrastructure.
3. Employment – the proposed project activity will provide direct employment to about 525 persons during the construction and 125 during the normal operation. In addition it is expected that up to 30 persons will be directly benefited through casual work, subcontracts, trading, etc..