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

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Annexes

Appendices

SECTION A. General description of project activity

A.1 Title of the project activity:

>> **"155 MW Gas based combined cycle power project at Hazira".**

Version 03

Dated: 20 February 2008

A.2. Description of the project activity:

Purpose of the project activity

Essar Steel Ltd. (ESTL) owns and operates an integrated HR Steel plant of 2.0 MTA capacity at Hazira. ESTL is setting up a 500 MW natural gas based combined cycle power plant (CCPP) through a special purpose vehicle Bhander Power Limited (BPL). The CCPP is being set up in two phases (Phase I – 155 MW, Phase II – 345 MW) next to ESTL's facility in Hazira.

The proposed project activity that is the subject matter of this PDD is the Phase-I 155 MW capacity of the CCPP. ESTL has obtained the necessary approvals from the regulatory authorities to this effect. The project activity receives NG in pipelines from ESTL, and water is pumped from the Tapi river. BPL and ESTL have entered into a 'Power Purchase Agreement'[1] under which BPL would supply 155 MW power to ESTL.

Reduction of greenhouse gas emissions

A gas turbine (GT) and generator package of 100 MW capacity at site conditions[2], has been procured from Tokyo Electric Power Company (TEPCO)'s Sodegaura Gas Turbine Power Station in Japan. A new dual pressure heat recovery steam generator (HRSG) with integral de-aerator with HP steam production of about 179 tonnes per hour (tph) and LP steam production of about 36 tph and a new steam turbine generator (STG) of 55 MW rated capacity under site conditions were also procured. No supplementary firing in HRSG is required. The steam generated from the HRSG is fed to the ST to generate power. Using the above mentioned major components, a plant with 155 MW rated capacity has been installed.

The GHG emissions are reduced as the project activity is an alternative to a previous planned coal based CPP at the same site which if installed would have led to higher GHG emissions as compared with the project activity that uses natural gas. The project activity avoids requirement to purchase power from the GEB grid that is predominantly supplied with coal/ lignite based power plants, and reduces requirement of its power generation in the grid, thereby avoiding emission of GHGs.

Views of the project participant on contribution of the project activity to sustainable development

The contribution of this project activity towards sustainable development as per the four indicators prescribed by National CDM Authority (NCDMA) in India i.e., Ministry of Environment and Forests (MoEF) is provided below:

Social well being:

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[1] A copy of the agreement is available for verification by the DOE

[2] Capacity 116.9 MW under ISO conditions (16°C and 60% relative humidity)

- The project activity has generated employment for the local population during the construction as well as operational phases of the project activity, both direct and indirect.
- It has also provided an opportunity for secondary small scale entrepreneurs development near the project site, such as small shops, etc. Overall, there has been employment creation as a result of the project activity. This has provided social security to local villagers in the area which was otherwise a saline wasteland without any productive use such as agriculture.
- The project activity avoids need for the Gujarat grid to provide electricity to the Essar operations at Hazira, whereby such power is now available for use in the area.
- Essar group has been supporting social initiatives in four areas namely:
    - Educational and self employment training: this is being done through supporting Hazira primary school by the way of building improvement; providing scholarships and sponsorship of events; instituting award for best student in local tailoring institute, among others
    - Infrastructure & Welfare Amenities – village community centre in Hazira village; water tank and pipeline; widening, re-carpeting and electrification of road
    - Recreational
    - Medical, Sanitation & Health Care needs: ambulance, drainage, community dust-bins, insecticides, eye-camps, health camp in primary school

Economic well being:

- By creating employment in the area, as described above, the project activity has brought in economic improvement for the local population.
- If the project activity is registered as a CDM project, then by way of generating CERs and through transaction of such CERs with Annex I Parties, the project activity would bring in additional revenue to India.

Environmental well being:

- The project activity avoids use of any other fossil fuels such as coal, lignite, naphtha, diesel, etc., and thus reduces emissions of GHGs, oxides of sulphur and nitrogen, particulate matters and unburned carbon, fly ash (in case of coal and lignite), etc.

Technological well being:

- The project activity is a natural gas based combined cycle power plant and would result in improved power generation efficiency.

A.3. Project participants:

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	Kind indicate if the Party involved wishes to be considered as project participant (Yes/No)
Government of India (Host Party)	1. Essar Steel Limited (ESTL) 2. Bhander Power Limited (BPL)	No

BPL will be the lead and nodal entity for all communication with CDM-EB and Secretariat. The contact information has been provided in Annex-I.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

>> Village Hazira, Taluka Choryasi, District Surat, Gujarat, India

A.4.1.1. Host Party(ies):

>> The Government of India

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

>> Gujarat

A.4.1.3. City/Town/Community etc:

>> Hazira

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

>> The project activity is located on a 20 hectare complex adjacent to an existing HBI manufacturing unit of Essar at Hazira at Longitude: 72°39´15"E; Latitude: 21°06´13"N and Altitude: 5.6 Meters (Above Mean Sea Level). This area is connected to the nearest city Surat (27 km away) by Surat-Hazira Road. The nearest port is at Hazira and railway station is at Surat. The Taluka is Choryasi and the District is Surat in the state of Gujarat.

The location map of the project activity is provided in Annex 5 at the end of this document.

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

>> As per the scope of the project activity listed in the "List of Sectoral scopes" (Document CDM-ACCR-06 version 03)', the project activity will principally 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 GT and generator package (MS 9161), GE Frame 9E, with a site rating of 100 MW capacity has been procured from TEPCO's Sodegaura Gas Turbine Power Station in Japan. A dual pressure HRSG (manufactured by Deltak, USA) and a STG of 55 MW rated capacity at site conditions were added to make a combined cycle electricity generation system. No supplementary firing in HRSG is required. In addition to the main plant equipment, auxiliary cooling water system, condenser cooling water system, electrical systems, evacuation of power, etc., are also parts of the power project. Also included are features for addressing environmental aspects and safety in operation and maintenance of the power project. Power generated from this project activity at BPL is evacuated at 220 kV to MRSS (main receiving sub-station) of ESTL which is connected to GETCO grid.

The necessary transmission lines for this purpose are installed by BPL. The GTG generator is connected to the bus in the switchyard through a 160 MVA generator transformer that steps up voltage from 15 kV to 220 kV provided with on load tap changers on the high voltage side. The STG generator is connected to the switchyard through a 70 MVA generator transformer that steps up voltage of 11 kV to 220kV. The connections from generator to respective generator transformers are through isolated phase bus ducts. The connection between HT side of generator transformers and the switchyard are by using overhead lines using ACSR conductor 220 kV HT cables. The overall plant gross heat rate is about 2,000 kCal/kWh on GCV basis.

The NG used as fuel for the project is a combination of NG and R-LNG (Regasified- Liquid Natural Gas) and is received by ESTL from various sources. The share of R-LNG is estimated to be 50% in energy terms. The Natural Gas from domestic sources is expected to have an average net calorific value of 8182 kCal/SCM[3] and LNG is expected to have an average net calorific value of 9300[4] kCal/SCM.

The only air pollutant from the project activity is NO_x which is within permissible limits specified by the Gujarat Pollution Control Board (GPCB). Adequate provisions for neutralising the effluents from the water treatment plant have been taken. The effluents from the entire power plant are treated as per the requirements.

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

>> The estimated emission reductions over the 10 year fixed crediting period (2007-2017) would be **1908760 tCO_{2e}** as per details on annual emission reductions provided below.

Years	**Annual estimation of emission reduction (tCO_{2e})**
Year 1	190876
Year 2	190876
Year 3	190876
Year 4	190876
Year 5	190876
Year 6	190876
Year 7	190876
Year 8	190876
Year 9	190876
Year 10	190876
Total estimated reductions (tCO_{2e})	**1908760**
Total number of crediting years	**10**
Annual average over the crediting period of estimated reductions (tCO_{2e})	**190876**

A.4.5. Public funding of the project activity:

>> There is no ODA involved in development of the proposed CDM project activity.

[3] Based on Gross Calorific Value (GCV) at 9000 kCal/scum and GCV:NCV ratio of 1.1 from "Thermal Performance Review 05-06, Section 9" of Central Electric Authority as available on http://cea.nic.in and

[4] Based on GCV at 9880 kCal/scum as per gas contract with the supplier

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:

>> Approved baseline methodology AM0029 (version 01.1 dated 19 May 2006) has been used to determine the baseline emissions and emission reduction due to the project activity. The title of this baseline methodology is **"Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas".**

The reference for this methodology is available on http://cdm.unfccc.int

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

>> The selected methodology AM0029 is applicable to the proposed CDM project activity. The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant. The justification for the various applicability conditions of AM0029 has been presented below.

The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant. Natural gas should be the primary fuel. Small amounts of other start-up or auxiliary fuels should be used, but can comprise no more than 1% of total fuel use.

The project activity is the construction and operation of a new combined cycle natural gas fired grid-connected[5] electricity generation plant that supplies electricity to ESTL at Hazira. The raw material used is natural gas and no auxiliary fuels are used.

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 baseline grid is western[6] regional electricity grid, whose geographical/ physical boundaries can be clearly identified and information pertaining to the grid and estimating baseline emissions is available in public domain on the website of the Central Electric Authority of India http://cea.nic.in.

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. In some situations, there could be price-inelastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project proponent to document that supply limitations will not result in significant leakage as indicated here.

Production of natural gas in India is at present at the level of around 87 million standard cubic meters per day (MMSCMD). The main producers of natural gas are Oil & Natural Gas Corporation Ltd.

[5] The project activity is connected to the GETCO grid through 220kV transmission lines from ESTL switchyard at Hazira. ESTL has obtained necessary clearances from the GETCO (Gujarat Energy Transmission Corporation Ltd.). All these references are available for verification by the DOE.

[6] Western regional grid is used as the default grid in pursuance with the CDM EB recommendations on grid selection.

(ONGC), Oil India Limited (OIL) and JVs of Tapti, Panna-Mukta and Revva. Out of the total production of around 87 MMSCMD, after internal consumption, extraction of LPG and unavoidable flaring, around 74 MMSCMD is available for sale to various consumers.

Under the Production Sharing Contracts, private parties from some of the fields are also producing gas. Government have also offered blocks under New Exploration Licensing Policy (NELP) to private and public sector companies with the right to market gas at market determined prices.

Most of the production of gas comes from the Western offshore area. The on-shore fields in Assam, Andhra Pradesh and Gujarat States are other major producers of gas. Smaller quantities of gas are also produced in Tripura, Tamil Nadu and Rajasthan States. OIL is operating in Assam and Rajasthan States, whereas ONGC is operating in the Western offshore fields and in other states. The gas produced by ONGC and a part of gas produced by the JV consortiums is marketed by the GAIL (India) Ltd. The gas produced by OIL is marketed by OIL itself except in Rajasthan where GAIL is marketing its gas. Gas produced by Cairn Energy from Lakshmi fields and Gujarat State Petroleum Corporation Ltd. (GSPCL) from Hazira fields is being sold directly by them at market determined prices.

As against the total allocation of around 118 MMSCMD, the gas supplies by GAIL is of the order of 63 MMSCMD spread over about 300 major consumers. Around 32% is supplied to the fertiliser sector, 41% to power, 4% to sponge iron and the balance 23% (including shrinkage) goes to other sectors.

At present, GAIL and GSPCL each are supplying 3 MMSCMD of Natural Gas in Gujarat from their gas fields located at Gandhar and Hazira basin respectively.

Petronet LNG and SHELL each have established LNG terminals having capacity of 2.5 MMTPA (10 MMSCMD) at Dahej and Hazira respectively. Thus, 20 MMSCMD of additional R-LNG is now available for supplies in Gujarat. Petronet and SHELL are planning to double the capacity of their terminal. The price of the R-LNG is in the range of 4 to 5 US$ per MMBTU for long-term contract and the spot price is about 10 to 11 US$ per MMBTU.

M/s Reliance in KG basin has discovered substantial gas. Supply is expected to be commenced by a pipeline from east coast to Gujarat. Reliance expects to produce 30-60 MMSCMD of gas from this discovery and more gas can be expected to be brought to western markets. State-owned Gujarat State Petroleum Corporation Limited (GSPCL) has struck gas in the Krishna Godavari basin, off Andhra Pradesh coast in the Bay of Bengal. This additional indigenous gas can be brought to Gujarat through the pipeline.

The project activity gets natural gas from ESTL who has dedicated gas supply agreements with several gas suppliers[7]. Thus gas quantities required for fulfilling this gas based economy vision are expected to be available in the envisaged time frame.

From the above paragraphs, it can be seen that the project activity satisfies all the applicability conditions of AM0029.

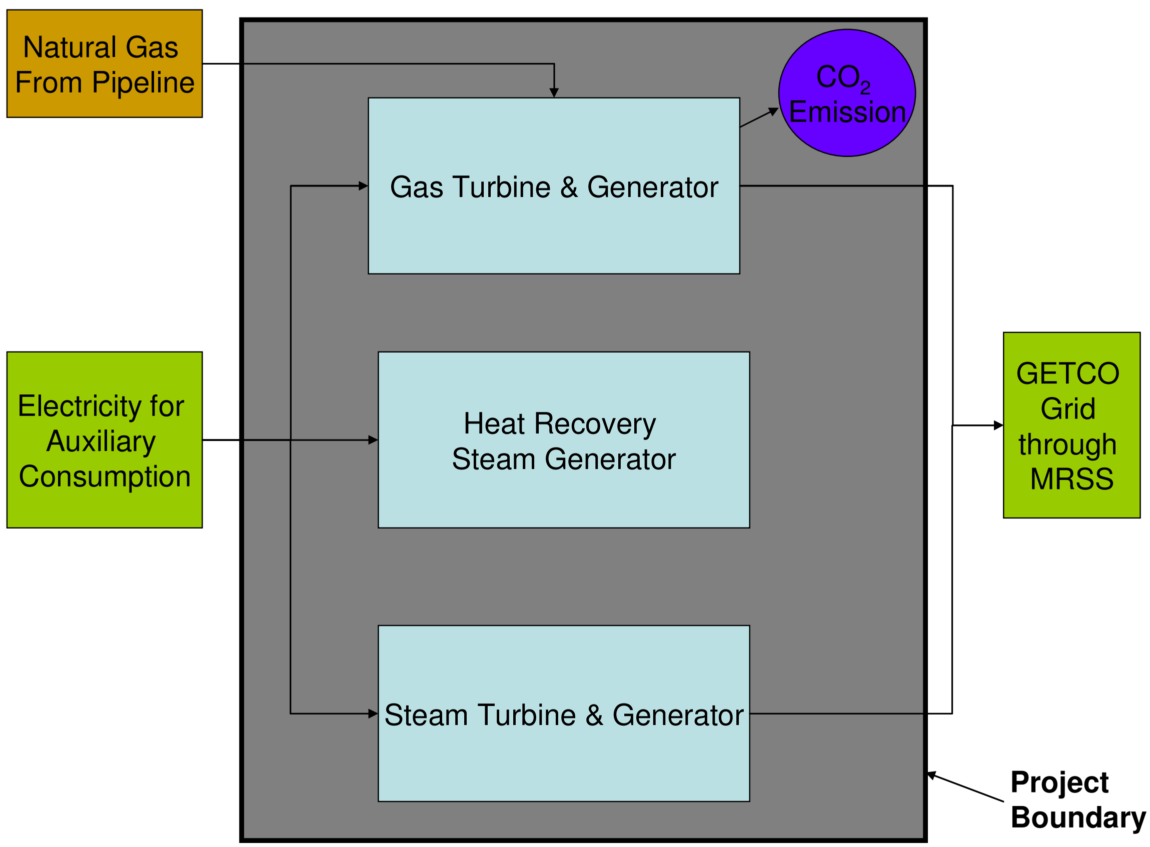
[7] Such as GAIL, GSPC + NIKO, IOC, BPCL, GSPC and Shell. The reference is available for verification by the DOE.

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

>> The spatial extent of the project boundary includes the equipment that form a part of Phase-1 155 MW CCPP at BPL's Hazira site as listed below and all power plants connected physically to the baseline grid as defined in ACM0002.

The equipments that form part of the project boundary are:

1. Gas Turbine Generator (GTG-1)
2. Steam Turbine Generator (STG-1)
3. Station transformers (ST-1 & ST-2)
4. Auxiliary equipments of Gas Turbine & Generator, Heat Recovery Steam Generator and Steam Turbine & Generator; meters; pipelines



In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion at the project plant are considered. In the calculation of baseline emissions, only CO_2 emissions from fossil fuel combustion in power plant(s) in the baseline are considered.

The greenhouse gases included in or excluded from the project boundary are shown in the table below:

Table 1: Overview of emissions sources included in or excluded from the project boundary

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation using coal/lignite/ naphtha as fuel	CO_2	Yes	Main emission source.
		CH_4	No	Excluded (conservative approach).
		N_2O	No	Excluded (conservative approach).
	Grid electricity generation in baseline	CO_2	Yes	Main emission source.
		CH_4	No	Excluded (conservative approach).
		N_2O	No	Excluded (conservative approach).
	Fuel processing and transportation	CO_2	Yes	Excluded (conservative approach).
		CH_4	No	Excluded (conservative approach).
		N_2O	No	Excluded (conservative approach).
Project Activity	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.
	Transportation of fuel to project site (inside the project boundary)	CO_2	Yes	Maybe significant emission source for NG/ LNG. Excluded for solid fuels.
		CH_4	Yes	Maybe significant emission source for NG/ LNG. Excluded for solid fuels.
		N_2O	No	Excluded for simplification.
	Processing and transportation of fuel outside the project boundary	CO_2	Yes	Accounted for leakage. This has been considered for conservativeness and prohibitive barriers to monitoring.
		CH_4	No	

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

>> As required under AM0029, 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.

In the absence of the project activity, one or more of the following could happen:

1. Establishing similar new generation capacity following the recent fuel choice trend in power generation in India, including addition of plants running on poor quality Indian coal (its quality is continuing to deteriorate); imported coal; or a mix of both; lignite; naphtha, among others,
2. Establishing similar new generation capacity power plant based on nuclear energy;
3. Establishing similar new generation capacity with renewable energy sources e.g., wind, hydro based power generation in India; and
4. Capacity additions to a number of existing power plants aggregating to the capacity of the project activity.
5. Import of electricity from connected grids, including the possibility of new interconnections

The baseline scenario has been identified using the steps provided in the applied baseline methodology as described below.

An important fact to note here is that the ESTL power plant had been designed for catering to the base load requirement. It is connected to the Western regional electricity grid.

On analysing the installed capacities of thermal power plants connected to the western grid over last 10 years, the pattern for fuel distribution emerges as follows:

Fuel	Installed capacity (MW)	Percentage of total installed capacity of 8846.5 MW
Coal	3260	36.85%
Lignite	325	3.67%
Gas	1847	20.88%
Nuclear	220	2.49%
Naphtha	48	0.54%

Based on the above information, the alternatives available to stakeholders in the grid which deliver base load power, are presented in the table below:

Scenario	Potential alternative conditions	Permitted by regulations
1.	Project activity implemented as a project without the CDM revenue	Yes
2.	New power plant (s) based on coal	Yes
3.	New power plant (s) based on lignite	Yes
4.	New power plant (s) based on naphtha	Yes
5.	New power plant (s) based on run-of-river[8] hydro power	Yes
6.	New power plant (s) based on nuclear power	Yes
7.	New power plant (s) based on wind energy	Yes
8.	Import of electricity from connected grids, including the possibility of new interconnections	Yes

All the above options are permitted by regulations. Analysis of all these options for their suitability as a most probable baseline scenario is presented in the sections below. For all the plausible options, levelized cost of electricity generation has been calculated in INR/kWh. The detailed levelized tariff calculations of all fuel/ technology options have been presented in Appendices 2, 3, 4 & 5 attached to this document.

<u>Scenario 1: Power generation using natural gas as fuel and combined cycle technology without CDM revenues</u>

<u>Technology</u>: Gas turbine plants operate on the Brayton cycle. They use a compressor to compress the inlet air upstream of a combustion chamber. Then the fuel normally Natural Gas / Liquefied Natural Gas is introduced and ignited to produce a high temperature, high-pressure gas that enters and expands through the turbine section. The turbine section powers both the generator and compressor. Gas turbines are also able to burn a wide range of liquid and gaseous fuels. The turbine's energy conversion efficiency typically remains low (@ 25-30 %) when utilised as an Open (simple) cycle. The simple cycle efficiency can be increased by installing a waste heat recovery boiler onto the turbine's exhaust. A waste heat recovery boiler captures waste heat in the turbine exhaust stream to preheat the compressor discharge air before it enters the combustion chamber. A waste heat boiler generates steam by capturing heat form the turbine exhaust. These boilers are known as heat recovery steam generators (HRSG). They can provide steam at high pressure and temperature which can be used to generate power with steam turbines, which is called a combined cycle (steam and Gas turbine operation). Thus HRSG and STG increase the overall energy cycle efficiency (@ 40-44 %).

[8] Storage, reservoir type hydro has been excluded since it deliver peak in power rather than base load power

Scenario 2: Power generation using coal as fuel

Technology: Fossil fuel-fired (coal) power plants use steam to provide the mechanical power to electrical generators. Pressurized high temperature steam or gas expands through various stages of a turbine, transferring energy to the rotating turbine blades. The turbine is mechanically coupled to a generator, which produces electricity. Steam turbine power plants operate on a Rankine cycle. The steam is generated by a boiler, where pure water passes through a series of tubes to capture heat from the furnace and then boils under high pressure to become superheated steam. The heat in the furnace is normally provided by burning fossil fuel (e.g. coal, fuel oil etc). The coal is fed to boiler after pulverization in the coal mills. The pulverized coal is transported to burners through primary air which is heated in Air Preheaters. The secondary air (preheated) is fed to boilers for complete combustion. The fuel firing normally takes place in the range of 1200-1300°C. The combustion chamber is enclosed by tubes termed as water wall tubes and these tubes form the gas tight chamber and water cooled furnace. The bottom ash is collected in the furnace bottom and fly ash carried along with the flue gases is collected in ESP hoppers and discharged to Ash areas. The superheated steam leaving the boiler then enters the steam turbine throttle, where it powers the turbine and connected generator to make electricity. After the steam expands through the turbine, it exits at the back end of the turbine, where it is cooled and condensed back to water in the surface condenser. This condensate is then returned to the boiler through high-pressure feed pumps for reuse. Heat from the condensing steam is normally rejected from the condenser to a body of water or cooling tower. The power plant efficiency is typically remains around 33 to 38%.

Scenario 3: Power generation using lignite as fuel

Technology: Fuel combustion in Circulating Fluid Bed system takes place in a vertical chamber referred to as the Combustor, in which the fluidisation of the fuel and the fuel combustion takes place. The fuel is preheated before entry and burnt at 850°C. The particle size of fuel used at bed is typically in the range of 6 – 12 mm. The bed material is fluidized by preheated primary air introduced through a grate at the bottom of the bed and by the combustion gases generated which flow upwards at a relatively high fluidizing velocity. The entire combustor contains a high concentration of suspended solids, which decrease continuously towards the top of combustor. The combustion gas entrains a considerable portion of the solids inventory from combustor. The bulk of these entrained solids is separated from the gas in the cyclone and is continuously returned to be bed by recycle loop. The very high internal and external circulating rates of solids, characteristics of the Circulating Fluid Bed, result in consistently uniform temperatures throughout the combustor and the solids recycle system. The long residence and contact times, coupled with the small particle sizes and efficient heat and mass transfer rates, produce high combustion efficiency. The relatively high ratio of solids circulation to fuel feed means that the Combustor is largely full of recycled solids and actual carbon content is surprising low. Further the large thermal inertia of the recycled solids allows the CFB system to handle high ash or high moisture fuels better than conventional combustion systems. Combustion of low volatile fuels like coke breeze in a CFB system is therefore more stable and of high efficiency. Combustion air is introduced into the combustor at multiple levels. About forty percent of the combustion air is passed as primary fluidizing air through the grate at the bottom and the balance is admitted as preheated secondary air through multiple ports in the side walls of the combustor. Combustion therefore occurs in two zones: a primary reducing zone in the lower section of the combustor, and complete combustion using excess air via the secondary air ports in the upper section. This staged combustion at controlled low temperatures of around 850°C, effectively suppresses NO_x formation. The entire combustor as well as the grate is enclosed by water walls and the lower water wall section is refractory lined to prevent corrosion and attack of the metal surfaces. The upper water wall section is not refractory lined and provides the majority of the evaporative duty of the boiler. The bottom ash discharged from the combustor is at 850°C and so it needs to be cooled in an ash cooler to approx. 200-250°C. The fly ash separated in the back pass and air preheater and the fly ash from the ESPs are collected in the hoppers. The steam from the steam generator is fed to turbine for power generation and turbine and other systems are similar to that of conventional Thermal Power plant. The power plant efficiency is typically remains around 28 to 33%.

Scenario 4: Power generation using naphtha as fuel

Technology: Naphtha turbine plants operate on the Brayton cycle. They use a compressor to compress the inlet air upstream of a combustion chamber. Then the fuel normally is introduced and ignited to produce a high temperature, high-pressure gas that enters and expands through the turbine section. The turbine section powers both the generator and compressor. The turbine's energy conversion efficiency typically remains low (@25-30 %) when utilised as a Open (simple) cycle. The simple cycle efficiency can be increased by installing a waste heat recovery boiler onto the turbine's exhaust. A waste heat recovery boiler captures waste heat in the turbine exhaust stream to preheat the compressor discharge air before it enters the combustion chamber. A waste heat boiler generates steam by capturing heat form the turbine exhaust. These boilers are known as heat recovery steam generators (HRSG). They can provide steam at high pressure and temperature which can be used to generate power with steam turbines, which is called a combined cycle (steam and Gas turbine operation). Thus HRSG and STG increase the overall energy cycle efficiency (@ 40-44 %).

Scenario 5: Power generation using hydro power

Technology: Power generation using hydro power can be in two ways:

1. run-of-river plants: these deliver base-load power
2. reservoir storage based plants: these deliver peak load power

The power generation facility delivering same services as ESTL's plant would be run-of-river based hydel power stations.

Potential in grid: In the western grid in last 5 years there has been no capacity addition in the run-of-river based hydro power generation with in the table below. From this data it is clear that in the state of Gujarat there is no untapped potential for development of hydroelectric power.

Region/ State	Identified Capacity per re-assessment study	Capacity Developed		PSS Developed	Capacity under construction		PSS U/C	Capacity Developed + under development		Capacity yet to developed	
	(MW)	(MW)	%	MW	(MW)	(%)	MW	(MW)	(%)	(MW)	%
Gujarat	619	555	89.7	1440	0	0	0	555	89.7	64	10.3

In the last five years the following hydel energy based power plants have been added to the western grid:

S.No.	Power Plant Name	State	Date of Addition	Capacity (MW)
1.	Indira Sagar HE – 8	Madhya Pradesh	23-Mar-05	125
2.	Sardar Sarovar RBPH - 1	Gujarat	1-Feb-05	200
3.	Indira Sagar HE – 7	Madhya Pradesh	29-Dec-04	125
4.	Sardar Sarovar HE - 4	Gujarat	15-Dec-04	50
5.	Indira Sagar HE – 6	Madhya Pradesh	27-Oct-04	125
6.	Sardar Sarovar HE - 3	Gujarat	7-Oct-04	50

S.No.	Power Plant Name	State	Date of Addition	Capacity (MW)
7.	Sardar Sarovar HE - 2	Gujarat	3-Sep-04	50
8.	Indira Sagar HE - 5	Madhya Pradesh	23-Jul-04	125
9.	Indira Sagar HE - 4	Madhya Pradesh	28-Mar-04	125
10.	Indira Sagar HE - 3	Madhya Pradesh	27-Feb-04	125
11.	Indira Sagar HE - 2	Madhya Pradesh	18-Jan-04	125
12.	Indira Sagar HE - 1	Madhya Pradesh	1-Jan-04	125
13.	Sardar Sarovar HE - 1	Gujarat	4-Sep-02	100
14.	Bansagar Tons - III - 3	Madhya Pradesh	24-Aug-02	20
15.	Bansagar Tons - II - 2	Madhya Pradesh	24-Aug-02	15
16.	Bansagar Tons - III - 2	Madhya Pradesh	25-Aug-01	20
17.	Bansagar Tons - II – 1	Madhya Pradesh	18-Feb-01	15

This data indicates that of the 1520 MW of addition in hydro power generation capacity, 95% has been with 50 MW plus size with storage hydro thereby catering to the peak-in load rather than base load of the grid. This makes run-of-the-river hydro energy based power generation as a non-plausible baseline option.

Scenario 6: Power generation using nuclear power

The most recent capacity additions in power plants in India are as follows:

S.No	Power Station Name	Promoter	Capacity (MW)	Date of Commissioning
1	TAPP 4	Nuclear Power Corp. Ltd.	540.00	March, 06
2	MAPPS-1	Nuclear Power Corp. Ltd.	50.00	Dec., 05

The nuclear energy based power generation in India does not fall in the purview of CERC/ SERCs and the tariff is unilaterally decided by Nuclear Power Corp. Ltd. There is no verifiable source of information available in public domain on the unit cost of power generation using nuclear energy. The levelized tariff of generation from nuclear energy is, however, higher than that from coal by about 15%[9] and hence has been excluded as a baseline option.

Scenario 7: Power generation using wind energy

The potential for wind energy based power generation in Gujarat has been estimated at 9675 MW[10] of which the cumulative installed capacity on 30.9.2005 is only 257.50 MW. Since the proposed CCPP is based on catering to the base-load and due to its inherent nature wind power generation will not qualify for "base-load firm power" because wind power projects are not subject to the dispatch rules as the coal or gas or hydro. This is also due to the fact that there is no scheduling and dispatching of wind power - the grid accepts wind power generation as and when the wind generators generate electricity.

Thus, wind energy based power generation cannot be strictly compared with the proposed project activity in terms of the services that it delivers and hence has been excluded as a baseline option.

[9] Projected Costs Of Generating Electricity, Update 1998 published by Nuclear Energy Agency of International Energy Agency & Organisation For Economic Co-Operation And Development

[10] Source: Ministry of Non-Conventional Energy Sources, Government of India.

Scenario 8: Import of electricity from connected grids, including the possibility of new interconnections

Given the grid data of last 3 years, there has been a steady rise in import of power from other grids by the western grid.

	Units	2004-05	2003-04	2002-03
Grid imports	GWh	4,690	1,137	1,849

This makes import of electricity from the interconnected grids a plausible baseline option.

Data on electricity trading (both intra regional grid and inter-regional grid) is made available at the Central Electricity Regulatory Commission's website (cercind.gov.in) which regulates inter-state electricity trading in India.

Levelized Tariff

For the scenarios 1,2,3 and 4 discussed in this section, the levelized tariff has been calculated based on two major components namely fixed cost and variable cost. The fixed cost includes the following factors[11] as per the guidelines prescribed by Central Electricity Regulatory Commission (CERC) and the terms and conditions of the Power Purchase Agreement between BPL and ESTL:

1. Return on Equity (ROE)
2. Debt: Equity ratio of 70:30.
3. Operation & Maintenance expenses: This is inclusive of employee cost, repairs and maintenance charges and administrative and general charges. O&M escalation at 6%.
4. Depreciation inclusive opening gross fixed assets and average additions during the year at 7.84%.
5. Interest on loan at actuals
6. Interest on working capital (WC): based on Prime Lending Rate (PLR) of State Bank of India at 12%
7. Normative Plant Load Factor (PLF) at 85%
8. Discount factor of 10%.
9. Tax on income at 33.66%.
10. MAT rate for the first 10 years considering 80IA benefit at 7.84%

The variable cost has been calculated based on the cost of the fuel and of water. The escalation in fuel price has been taken uniformly at 3% for natural gas, coal, lignite and naphtha.

Levelized tariff for gas:

The levelized tariff comes out as INR 2.63/ kWh. This has been calculated based on the following factors:

Capacity in MW	155	Aux. Consumption	3.00%
Rate of Depreciation	7.84%	SHR (Kcal/Unit) based on GCV	2000
Per MW Cost (INR million)	18.3	Price of Fuel (USD/SCM) [11]	3.95
Total Debt (INR million)	1960	GCV (Kcal/kg)	9850

[11] Reference: Tariff Order no L-7/25(5)/2003-CERC of Central Electricity Regulatory Commission dated 26 March 2004

[11] The relevant actual price details will be shared at the time of validation

Total Equity (INR million)	881.6	O&M Expenses (per MW/yr)	0.78 Million

Levelized tariff for coal: The levelized tariff for power generation with coal comes out as INR 2.44/kWh. This has been calculated based on the following factors:

Capacity in MW	165	Aux. Consumption	9.00%
Rate of Depreciation	7.84%	SHR (Kcal/Unit)	2500
Per MW Cost (INR million)	40.00	CIF Price of Fuel (USD/MT)	50
Total Debt (INR million)	4619.7	GCV (Kcal/kg)	6300
Total Equity (INR million)	1979.9	Customs Duty on Coal	5%
O&M Expenses (per MW/yr)	1.04 Million		

Levelized tariff for lignite: The levelized tariff for power generation with lignite comes out as INR 2.52/kWh. This has been calculated based on the following factors:

Capacity in MW	165	Aux. Consumption	9.5%
Rate of Depreciation (up to 90%)	7.84%	SHR (Kcal/Unit)	2750
Per MW Cost (INR million)	43	Price of Fuel (INR/ MT)	876
Total Debt (INR million)	4964.8	GCV (Kcal/kg)	2673
Total Equity (INR million)	2127.8	O&M Expenses (per MW/yr)	1.1 Million

Levelized tariff for naphtha:

The levelized tariff for power generation with naphtha comes out as INR 7.85/kWh. This has been calculated based on the following factors:

Capacity in MW	155	Aux. Consumption	3.00%
Rate of Depreciation (up to 90%)	7.84%	SHR (Kcal/Unit)	2000
Per MW Cost (INR million)	21.3	Price of Fuel (INR/KL)	30000
Total Debt (INR million)	2315.4	GCV (Kcal/kg)	11000
Total Equity (INR million)	992.3		

Levelized tariff for import of power from the connected grids

The data available from CERC on electricity trading, as mentioned above, shows that the weighted average sale price for the year 2004-05 was Rs. 3.23 per kWh and this went up to Rs. 4.52 per kWh in the year 2005-06. We have used the data for 2005-06 as the indicative tariff for import of power from connected grids.

Summary of levelized tariff for all plausible baseline options is as follows:

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
1.	Project activity implemented as a project without the CDM revenue	2.63
2.	New power plant (s) based on coal	2.44
3.	New power plant (s) based on lignite	2.52
4.	New power plant (s) based on naphtha	7.85
5.	Import of electricity from connected grids, including the possibility of new interconnections	4.52

A sensitivity analysis was performed on the data above for the following factors:

1. Price of Fuel: increase and decrease in base price of fuel by 10% and 20%.
2. Escalation rate for the fuel price: increase and decrease by 25% and 50%.
3. Station Heat Rate (SHR): increase and decrease by 1% and 2%.

4. Plant Load Factor (PLF): increase and decrease by 5% and 10%.

The results of sensitivity analysis on levelized tariff of generation for various fuels are presented in the table below:

Fuel Base Price Variation

Fuel	-20%	-10%	+10%	+20%
Gas	2.20	2.41	2.85	3.07
Coal	2.17	2.30	2.57	2.71
Lignite	2.17	2.39	2.65	2.77
Naphtha	6.38	7.12	8.58	9.31

Fuel Price Variation

Fuel	-50%	-25%	+25%	+50%
Gas	2.39	2.51	2.77	2.92
Coal	2.29	2.36	2.52	2.62
Lignite	2.38	2.44	2.60	2.69
Naphtha	7.04	7.43	8.31	8.82

PLF Variation

Fuel	-10%	-5%	+5%	+10%
Gas	2.68	2.65	2.61	2.59
Coal	2.55	2.49	2.39	2.34
Lignite	2.64	2.58	2.47	2.41
Naphtha	7.90	7.88	7.82	7.80

Heat Rate Variation

Fuel	-2%	-1%	+1%	+2%
Gas	2.59	2.61	2.65	2.67
Coal	2.41	2.42	2.45	2.47
Lignite	2.49	2.51	2.53	2.55
Naphtha	7.71	7.78	7.92	7.99

From the data presented above, it can be observed that with variations in price of fuel, escalation rate for the fuel price, SHR and PLF, power generation using natural gas as fuel continues to remain more expensive than power generation using coal as fuel, thus substantiating that the project activity is not the economically most attractive route for power generation for any stakeholder connected to the western grid in India.

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):

>> The proposed power plant uses natural gas, a comparatively less GHG intensive fuel compared to other fossil fuels like coal, etc., resulting in reduction of anthropogenic emission of GHGs. There is no legal requirement in India to choose natural gas in preference to higher GHG intensive fuels like coal. Originally, ESTL had proposed to use coal as the fuel and had obtained all requisite clearances in that regard.

The national and sectoral policies that may guide the implementation of above options can be understood from discussions provided under the previous section. As per existing national legislation

/ regulation applicable to like projects there is no restrictions on utilization of any fuel for Grid Connected Generating stations. Therefore, the Natural Gas Based Power Project could have been installed using either of the following fuels, viz. Coal, Lignite, Naphtha, HSD, LSHS etc. with conventional technologies.

The project activity leads to additional GHG emission reductions than that would have occurred in its absence. In order to demonstrate that the project activity is not a baseline scenario, the following steps are followed for additionality demonstration as recommended in the applied baseline methodology.

Steps for Additionality Check

Step 1: Benchmark investment analysis

Demonstrate 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 demonstration assessment and of additionality" agreed by the CDM Executive Board.

To determine whether the proposed project activity is economically or financially less attractive than the other alternatives without the CDM revenues, the sub-steps 2b, 2c and 2d have been followed as required under AM0029.

Sub-step 2(b): Benchmark Analysis (Option III: Apply benchmark analysis)

Based on Option III of sub-step (2b), the indicator that has been selected for benchmark analysis is the levelized tariff from power generation in INR/kWh.

Sub-step 2c (Calculation and comparison of financial indicators)

The levelized tariff for all the plausible options to the proposed project activity has been calculated and presented in Section B.4 above. A summary of these levelized tariff[12] calculations is presented in the table below:

S.No.	Baseline option	Levelized Tariff (INR/kWh)
1.	Power generation using Natural gas	2.63
2.	Power generation using Coal	2.44
3.	Power generation using Lignite	2.52
4.	Power generation using Naphtha	7.85
5.	Import of power from the interconnected grids	4.52

On analysing this data it can be clearly seen that the project activity is not the most economical for power production. Using coal as fuel is economically the most feasible investment for producing power in the western grid. Amongst all the above options, the GHG emissions will be more than the project option.

The Cost of Power Generation using coal as fuel is considered as the benchmark, as this is the most economic and technologically viable project option for the project proponent.

The cost per kWh of power at INR 2.63 for the proposed CDM project activity is higher than two of the plausible alternative options i.e. coal based power generation and lignite based power generation.

[12] The detailed excel sheets of these calculations are available with the project proponent for verification by DOE.

Sub-step 2d (Sensitivity Analysis)

The findings of sensitivity analysis on levelized tariff of generation for natural gas, coal and lignite presented in section B.4 above further substantiates that even with reasonable variations in price of fuel, escalation rate for the fuel price, SHR and PLF, power generation using natural gas as fuel continues to remain more expensive than power generation using coal or lignite as fuels.

The project faces further price and currency risks due to:

- the volatility in the price of crude oil and natural gas
- Government of India's policy to eventually align the domestic gas prices to global fuel prices.
- the government permitting consortiums exploring new blocks and the Panna Mukta Consortium (producing 11 MMSCM of natural gas currently) to charge market determined prices. Also price of LNG marketed in India is tied to crude oil prices effective 1st January 2009 though it is fixed until then.

Step 2: Common practice analysis

Demonstrate that the project activity is not common practice in the relevant country and sector by applying Step 4 (common practice Analysis) of the latest version of the “Tool for demonstration assessment and of additionality” agreed by the CDM Executive Board.

Sub-step 4(a). Analyze other activities similar to the proposed project activity

The following paragraphs, analyze “Other Activities (implemented or underway) similar to Project Activity”, on the various parameters (Region and broad technology, Regulatory regime, Technology, Access to financing and Changes in investment climate):

Region and broad technology:

The Indian power system is divided into five independent regional grids, namely Northern, Eastern, Western, Southern, and North-Eastern[13]. As the Project Activity is located in the Western Grid, we would consider Other Activities that are in the Western Grid. Further, as the Project Activity employs combined cycle gas turbine (CCGT) technology, we have considered Other Activities as CCGTs operating or under implementation during the year 2004 which is the Starting Date of Project Activity (refer Section C.1.1 below), in the Western Grid.

Out of 80 power plants in the Western Grid in 2004 – 05, there were 14 power plants implemented in the Western Grid using CCGT technology[14] and one plant under implementation using CCGT technology[15].

These plants are listed in the table on the below.

[13] Source: Page 2, CEA User Guide, http://cea.nic.in/planning/c%20and%20e/user_guide_ver2.pdf

[14] Source: CEA Database http://cea.nic.in/planning/c%20and%20e/Database_publishing_ver2.zip

[15] Source: CEA Project Monitoring Reports for Gujarat, Maharashtra, Madhya Pradesh, Chattisgarh and NTPC downloaded on 11 May 2004; Enclosed as Appendix 6A to 6E; the one plant using CCGT is in Appendix 6C, Serial No 2

Sl. No.	Power Plant Name	Capacity (MW)	Located in	Implementation Time	Private / Government	Implemented/ under implementation in 1991-92	Implemented /began implementation prior to 2002	Multi-fuel or single fuel (natural gas(NG))	Gross Generation 2004 – 05 (GWh)
Activities Implemented									
1	Dhuvaran	534	Gujarat	**1964-71**	Government	**Yes**	**Yes**	**Multi-fuel (oil and gas)**	**2,114 (on LSHS)**
2	Uran GT	912	Maharashtra	**1986-94**	Government	**Yes**	**Yes**	Single fuel (NG)	**4,113**
3	Vatwa TORR	100	Gujarat	**1990-91**	Private	**Yes**	**Yes**	**Multi-fuel (gas and oil)**	**557**
4	G.I.P.C.L. GT	305	Gujarat	**1990-97**	Government	**Yes**	**Yes**	**Multi-fuel (gas and naphtha)**	**2,260**
5	Utran GT	144	Gujarat	**1992-93**	Government	**Yes**	**Yes**	Single fuel (NG)	**1,175**
6	Kawas GT	644	Gujarat (Ntpc)	**1992-93**	Government	**Yes**	**Yes**	**Multi-fuel (gas and naphtha)**	**2,824**
7	Trombay GT	180	Maharashtra	**1993-94**	Private	**Yes**	**Yes**	Single fuel (NG)	**1,335**
8	Gandhar GT	648	Gujarat (Ntpc)	1994-95	Government	No	**Yes**	Single fuel (NG)	**4,032**
9	Essar Gt Imp.	515	Gujarat	1995	Private	No	**Yes**	**Multi-fuel (gas and naphtha)**	**3,387**
10	Dhabol GT	2184	Maharashtra	1998	Private	No	**Yes**	**Multi-fuel (naphtha and LNG)**	**0 (Stopped generation)**
11	Paguthan	655	Gujarat	1998	Private	No	**Yes**	**Multi-fuel (gas and naphtha)**	**3,655**
12	Reliance Energy	48	Goa	1999	Private	No	**Yes**	**Single-fuel (naphtha)**	**336**
13	Hazira CCCP Gseg	156	Gujarat	2000	Government	No	**Yes**	Single-fuel (NG)	**1,151**
14	Dhuvaran CCPP	106	Gujarat	2003	Government	No	No	Single-fuel (NG)	**701**
Activities under Implementation									
1	Dhuvaran CCPP Extn	112	Gujarat	2006	Government	No	No	Single-fuel (NG)	

During 2004 – 05, the operating gas based units generated 25,526.35 GWh compared to the total generation of 184084.41 GWh in Western Grid[16]. This implies a penetration of 14%, i.e., a significant majority of the electricity generation (86%) has been from non-CCGT plants. This includes electricity generation from a major share of conventional pulverized fuel fired coal based and lignite based power plants (141,964 GWh or 77% of the Western Grid generation).

Regulatory regime:

Government of India came out with a policy for private sector participation in generation of electricity in Oct 1991[17]. Prior to that, only state and federal governments, the entities promoted by the state/federal governments and select private licensees (Tata Power, BSES, Ahmedabad Electric, etc.) which were not nationalized under the Indian Electricity Act 1910 were allowed to invest in power sector generation. 7 out of the 14 CCGT power plants mentioned above were implemented or under implementation when the new 1991 policy was announced. As these 7 projects enjoyed special status (for having exclusive right to invest in power generation projects) under the pre-1991 regulatory framework, these are excluded from being part of Other Activities. The remaining 7 power plants contributed to generation of 13,262 GWh in 2004 – 05 or a penetration of 7%[18].

Technology:

Out of the remaining 7 power plants mentioned above, three power plants (Essar GT 515 MW, Gujarat Paguthan 655 MW, Dabhol GT 2184 MW) have multi-fuel firing capabilities while one is designed to run on Naphtha (Reliance Energy 48 MW). Multi-fuel fired CCGTs are not only technologically different (burner design, storage tanks, pipelines, etc.) but also have greater flexibility to choose within a range of fuels, depending on economics and availability and are thus better able to diversify fuel risks and dispatch risks, as compared to single (natural gas) fired plants. Thus, these multi-fuel fired plants and naphtha fired plant are excluded from Other Activities. The remaining 3 Other Activities that are similar to the Project Activity generated 5,884 GWh or 3% of the total Western Grid generation[19].

Access to financing:

Kawas GT 644 MW (set up before 1991) and Gandhar GT 648 MW are set up by National Thermal Power Corporation (http://www.ntpc.co.in), the largest generator in India and owned by Government of India. NTPC's financial strength and its access to financing is significantly better than other companies in India. For example for the Gandhar GT 648 MW power project, this was funded through Japanese Overseas Development Assistance[20] and Kawas GT 644 MW has international assistance from France and Belgium[21]. The projects developed by NTPC therefore have been

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[16] Source: table 3.4 of CEA General Review 2006; http://cea.nic.in/power_sec_reports/general_review/0405/index.pdf, also provided in Appendix 7 attached herewith

[17] Source: Ministry of Power Annual Report 1991-92; Page 28; http://powermin.nic.in/reports/pdf/ar91-92.pdf) and http://www.adbi.org/discussion-paper/2007/04/26/2236.policy.environment.power.sector/policy.developments.for.private.investment.in.the.indian.power.sector

[18] Source: CEA Database http://cea.nic.in/planning/c%20and%20e/Database_publishing_ver2.zip

[19] Source: CEA Database http://cea.nic.in/planning/c%20and%20e/Database_publishing_ver2.zip

[20] http://www.jbic.go.jp/english/oec/post/2002/pdf/105_full.pdf

[21] http://www.ntpc.co.in/powerplants/ntpc_pw_kawas.shtml

excluded from Other Activities. The remaining 2 Other Activities that are similar to the Project Activity generated 1,852 GWh or 1% of the total Western Grid generation.

Changes in investment climate:

It is important to distinguish between the investment climate that prevailed notably prior to the Dabhol Power Project and after. In 1992, pursuant to the 1991 power policy, Maharashtra State Electricity Board (MSEB) (with counter guarantee from Government of India) entered in to an agreement with Enron to set up a 2184 MW Naphtha/LNG fired power project at Dabhol, Maharashtra. The project was set up in two phases (phase – I, 740 MW & phase – II, 1444 MW). The phase – I of the project took 9 years to complete and started generating in 1998. In 2001, it went into dispute with the offtaker and stopped generation. Due to this dispute, phase – II of the project never entered commercial operation even though almost the entire investment was made. Since then, there have been a number of legal and regulatory cases, arbitration, political interventions, etc. and the project is yet to re-start generation.

The investment climate that prevailed after the announcement of the 1991 policy where everything was done to facilitate private sector investment and under which investments like Essar GT 515 MW, Paguthan 655 MW and Dabhol 2184 MW came up completely reversed post 2002 after Dabhol's failure. Many power projects were shelved in the aftermath of Dabhol, and a number of foreign investors pulled out notably Cogentrix (Mangalore power project), China Light and Power (Hirma Power Project), CMS Energy. Thus, the projects that began implementation prior to 2002 (and especially during the 1992 – 95 period) faced very different and favourable investment climate as compared to the projects that began implementation after 2002[22]. Except the Dhuvaran CCPP/CCPP Extn projects, all other projects began implementation prior to 2002. The Dhuvaran CCPP 106 MW and Dhuvaran CCPP Extn 112 MW projects have been proposed as CDM project activity[23].

Sub-step 4(b). Discuss any similar options that are occurring

As discussed under Sub-step 4(a) above, there are no Other Activities that are similar to the Project Activity and hence the Sub-Step 4(b) is not applicable to the Project Activity. This thereby demonstrates that the project activity is not a common practice.

Step 3: Impact of CDM registration

Describe the impact of the registration of the project activity by applying Step 5 (Impact of CDM registration) of the latest version of the "Tool for demonstration assessment and of additionality" agreed by the CDM Executive Board.

The latest version of "Tool for demonstration assessment and of additionality" version 3 EB29 has done away with Step 5 and therefore this has not been analysed.

[22] http://timesofindia.indiatimes.com/articleshow/1602986123.cms; Appendix 8

[23] http://cdm.unfccc.int/Projects/DB/BVQI1190262498.56/view

Based on the findings from above steps it is established that project activity itself is not the baseline scenario and hence is additional.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

>> According to the approved baseline methodology AM0029, the emission reductions ERy by the project activity is calculated using the following equation

ERy = BEy – PEy – Ly……………….(1)

Where:

ERy : emissions reductions in year y (t CO2e)

BE_y : emissions in the baseline scenario in year y (t CO_2e)

PE_y : emissions in the project scenario in year y (t CO_2e)

LE_y : leakage in year y (t CO_2e)

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:

$$BE_y = EG_{PJ,y} * EF_{BL,CO_2,y} \qquad (3)$$

For construction of large new power capacity additions under the CDM, there is a considerable uncertainty relating to which type of other power generation is substituted by the power generation of the project plant. However, for the proposed CDM project activity as mentioned in the Section B.4 above, power generation using imported coal as fuel is the baseline scenario.

AM0029 advises to address the baseline uncertainties in a conservative manner by choosing the $EF_{BL,CO2,y}$ as the lowest emission factor among the following three options:

Option 1. The build margin, calculated according to ACM0002; and

Option 2 The combined margin, calculated according to ACM0002, 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:

$$EF_{BL,CO_2}(tCO_2 / MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ / MWh \qquad (4)$$

where,

$COEF_{BL}$ = the fuel emission coefficient (tCO_2e/GJ), based on Table 2.2 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories

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

As per AM0029, the baseline emission factor determination is required to be made once at the validation stage based on an *ex ante* assessment and once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, then they will be estimated *ex post*, as described in ACM0002.

Option 1: Build Margin, calculated according to ACM0002

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

$$EF_{BM,y} = [\sum_i F_{i,m,y} * COEFi] / [\sum_k GEN_{k,m,y}] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..(4)$$

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

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

The Central Electricity Authority, Ministry of Power, Government of India has published a database of Carbon Dioxide Emission from the power sector in India based on detailed authenticated information obtained from all operating power stations in the country. This database i.e. The CO2 Baseline Database provides information about the Operating Margin and Build Margin Emission Factors of all the regional electricity grids in India. The Operating Margin in the CEA database is calculated ex ante using the Simple OM approach and the Build Margin is calculated ex ante based on 20% most recent capacity additions in the grid based on net generation as described in ACM0002. We have, therefore, used the Operating Margin and Build Margin data published in the CEA database for calculating the baseline emission factor.

The Build Margin as per CEA database is 0.6300 tCO2e/MWh

Option 2 The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight.

The combined margin emission factor as per ACM0002, is calculated as a combination of the Operating Margin (OM) and the Build Margin (BM). Considering the emission factors for these two margins as $EF_{OM,y}$ and $EF_{BM,y}$, then the EFy is given by:

$$EFy = w_{OM} * EF_{OM,y} + w_{BM} * EF_{BM,y} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..(5)$$

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

As instructed in AM0029, we have used a 50/50 weight for OM and BM while calculating the combined margin emission factor.

Operating Margin emission factor

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

The Simple Operating Margin approach is appropriate to calculate the Operating Margin emission factor applicable in this case. As per ACM0002 the Simple OM method can only be used where low cost must run resources constitute less than 50% of grid generation based on average of the five most recent years. The generation profile of the Western grid in the last five years is as follows:

Generation in GWh	**2004-05**	**2003-04**	**2002-03**	**2001-02**	**2000-01**
Low cost/must run sources					
Hydro	10,610	9,282	8,172	7,928	7,174

Wind & Renewables	884	1,522	879	610	314
Nuclear	5,100	5,700	6,200	6,073	5,903
Other sources					
Coal	141,964	136,063	137,392	133,628	128,561
Diesel	-	-	-	-	-
Gas	25,526	21,508	18,713	16,072	21,280
Total Generation	**184,084**	**174,075**	**171,356**	**164,311**	**163,232**
Low cost/must run sources	16,594	16,504	15,251	14,611	13,391
Low cost/must run sources	9%	9%	9%	9%	8%

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

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

As mentioned earlier, Operating Margin in the CEA database has been calculated using the Simple OM method. We have therefore considered the OM numbers provided in the CEA database.

Operating margin data for the Western region electricity grid for the latest three years available in the CEA database are given below:

Year	Operating Margin (tCO2e/MWh)
2003 – 04	0.9903
2004 – 05	1.0119
2005 – 06	0.9934
Average of 3 years	0.9985

The Operating Margin applicable for the project activity is taken as average of the latest three years operating margins. Accordingly the Operating Margin is determined as 0.9985 tCO2e/MWh.

As mentioned earlier, the applicable Build Margin value is 0.6300 tCO2e/MWh.

Applying a 50/50 weightage to the values for operating margin and build margin emission factors provided in the CEA database, the Combined Margin emission factor is calculated as 0.8142 tCO2e/MWh.

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

As demonstrated under section B.4 earlier, coal based power generation represents the technology that represents an economically attractive course of action, taking into account barriers to investment and therefore coal based power generation has been identified as the baseline scenario.

The emission factor of coal based power generation calculated using the equation below:

$$EF_{BL,CO_2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \qquad (6)$$

$COEF_{BL}$ = Carbon Emission Factor of coal x Oxidation Factor of coal x 44/12

Based on IPCC 2006 value, $COEF_{BL}$ = 94.60 tCO_2/TJ = 0.0946 tCO_2/GJ

η_{BL} = 38% (refer Annex 3 for calculations)

$EF_{BL,CO2}(tCO2/MWh)$ = 0.0946 (tCO2e/GJ) x 3.6 (GJ/MWh)/38%

= 0.896 tCO2e/MWh

Baseline Emission Factor

Emission factors determined using the three options are summarised in the table below

Option	Emission Factor (tCO2e/MWh)
Option 1: Build Margin	0.630
Option 2: Combined Margin	0.8142
Option 3: Emission factor of coal based power plant	0.896

Option 1: Build Margin value is the lowest of all the three options and hence the appropriate Baseline Emission Factor. Accordingly, Baseline Emission Factor value applicable to the project activity is 0.630 tCO2e/MWh.

As per AM0029, in case the Build Margin or the Combined Margin is selected as the baseline emission factor, the baseline emission factor (Build Margin) will be determined ex-post, as described in ACM0002. As per ACM0002, in case of ex-post determination, the Build Margin must be updated annually ex-post for the year in which the actual generation and associated emission reduction occur. The latest version of CEA CO2 baseline database that is used to determine the BM factor was published in June2007 and contains information up to 2005-06. CEA has acknowledged that because of the dynamic nature of data, the database will have to be updated every year. Therefore we expect the CEA database to be updated every year. If the CEA database is not updated, the Build Margin number will be calculated by the project proponent using CEA data.

Project emissions

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

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \qquad (2)$$

Where:

$FC_{f,y}$: 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’

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

$$COEF_{f,y} = \sum NCV_y * EF_{CO_2,f,y} * OXID_f \qquad (2a)$$

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) taken from IPCC;

$OXID_f$: is the oxidation factor of natural gas

For start-up fuels, IPCC default calorific values and CO_2 emission factors are acceptable, if local or national estimates are unavailable.

Applicable values for the above parameters are provided below:

NCVy: Calorific value of Natural Gas consumed by the Project activity is: 8,581 kCal/SCM or 35,926.92 KJ/SCM

$EF_{CO2,f,y}$: CO2 emission factor per unit of energy of Natural gas is determined as follows:

$EF_{CO2,f,y}$ = Carbon Emission Factor x 44/12

IPCC default value for Carbon Emission Factor of Natural Gas is 56.10 tCO2e/tJ

$EF_{CO2,f,y}$ = 56.10 tCO2e/tJ

$OXID_f$: Oxidation factor of Natural Gas as per IPCC Guidelines is 0.995

$COEF_{f,y}$: CO_2 emission coefficient for Natural Gas is determined as:

$COEF_{f,y}$ = 35,926.92/10^9 (tJ/SCM) x 56.10 (tCO2e/tJ) x 0.995

$COEF_{f,y}$ = 2,005.42 tCO2e/Mcum

Leakage

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH_4 emissions and CO_2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered:[24]

Fugitive CH_4 emissions associated with fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of natural gas used in the project plant and fossil fuels used in the grid in the absence of the project activity.

In the case LNG is used in the project plant: CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression into a natural gas transmission or distribution system.

Thus, leakage emissions are calculated as follows:

$$LE_y = LE_{CH4,\,y} + LE_{LNG,\,CO2,\,y} \qquad (5)$$

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 t CO_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 t CO_2e

Fugitive methane emissions

For the purpose of estimating fugitive CH_4 emissions, project participants should multiply the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH_4 emissions ($EF_{NG,upstream,CH4}$) from natural gas consumption and subtract the emissions occurring from fossil fuels used in the absence of the project activity, as follows:

[24] The EB is undertaking further work on the estimation of leakage emission sources in case of fuel switch project activities. This approach may be revised based on outcome of this work.

$$LE_{CH4,y} = \lfloor FC_y.NCV_y.EF_{NG,upstream,CH4} - EG_{PJ,y}.EF_{BL,upstream,CH4} \rfloor .GWP_{CH4} \quad (6)$$

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 tCH_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

The emission factor for upstream fugitive CH_4 emissions occurring in the absence of the project activity ($EF_{BL,upstream,CH4}$) should be calculated consistent with the baseline emission factor ($EF_{BL,CO2}$) used in equation (4) above. As presented in Annex 3, the emission factor was found to be the lowest with Build Margin method for the western grid, so the same calculation procedure has been adopted to calculate $EF_{BL,upstream,CH4}$, as presented below:

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

where:

$EF_{BL,upstream,CH4}$ 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

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 CH_4 per MJ fuel produced

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

CO_2 emissions from LNG

Where applicable, CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

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

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

FC_y Quantity of natural gas 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

Where reliable and accurate data on 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 is available, project participants should use this data to determine an average emission factor. Where such data is not available, project participants may assume a default value of 6 t CO_2/TJ as a rough approximation[25]. Where total net leakage effects are negative ($LE_y < 0$), project participants should assume $LE_y = 0$.

Default values used for calculating leakage emissions due to the project activity are as follows:

Sl. No	Parameter	Default Value	Remarks
1	Emission factor for fugitive CH4 upstream emissions for coal	0.8 tCH4/kt coal	Most of the coal production in India comes from open pit mines contributing over 81% of the total production.. A number of large open pit mines of over 10 million tonnes per annum capacity are in operation. Underground mining currently accounts for around 19% of national output. (http://www.mbendi.co.za/indy/ming/coal/as/in/p0005.htm). Hence 0.8 tCH4/kt coal value is used for surface mining
2	Emission factor for fugitive CH4 upstream emissions for Oil	4.1 tCH4/PJ	As per the Table 2 of the methodology. This value includes for oil production, transport, refining and storage.
3	Emission factor for fugitive CH4 upstream emissions for Natural Gas	160 tCH4/PJ	As per the Table 2 of the methodology, 296 tCH4/PJ is applicable for rest of the world and 160 tCH4/PJ is for USA and Canada. However, the US/Canada value is used as the system element (gas production and/or processing/ transmission / distribution) is predominantly of recent vintage and built and operated to international standards. GAIL is maintaining all its processing plants and gas transmission lines matching the international standards and are of recent vintage. GAIL also formulating a guidelines for the pipelines along with the BIS for development of uniform standards for high-pressure oil and gas transmission pipeline systems. Also GAIL conducts the regular safety

[25] This value has been derived on data published for North American LNG systems. “Barclay, M. and N. Denton, 2005. Selecting offshore LNG process. http://www.fwc.com/publications/tech_papers/files/LNJ091105p34-36.pdf (10th April 2006)”. .

Sl. No	Parameter	Default Value	Remarks
			audits to maintain the international safety standards with some reputed international firms
4	Oxidation factor of natural gas	0.995	IPCC value as per 2006 IPCC guidelines for National Green House Gas inventories

Leakage calculations are provided in Annex-6.

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 (tCH_4/MWh) will also be determined ex-post.

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

>> The data/ parameters that are available at validation include the following:

Data / Parameter:	***$EF_{BM,y}$***
Data unit:	tCO2e/MWh
Description:	Build Margin Emission Factor of Western Regional Electricity Grid
Source of data used:	"CO2 Baseline Database for Indian Power Sector" Version 2.0 dated 21 June 2007 published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO2 Baseline Database for Indian Power Sector" is available at www.cea.nic.in
Value applied:	0.630
Justification of the choice of data or description of measurement methods and procedures actually applied :	Build Margin Emission Factor has been calculated by the Central Electricity Authority in accordance with ACM0002.
Any comment:	-

Data / Parameter:	***$EF_{OM,y}$***
Data unit:	tCO2e/MWh
Description:	Operating Margin Emission Factor of Western Regional Electricity Grid
Source of data used:	"CO2 Baseline Database for Indian Power Sector" Version 2.0 dated 21 June 2007 published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO2 Baseline Database for Indian Power Sector" is available at www.cea.nic.in
Value applied:	2003 – 04: 0.9903 2004 – 05: 1.0119 2005 – 06: 0.9933
Justification of the	Operating Margin Emission Factor has been calculated by the Central

choice of data or description of measurement methods and procedures actually applied :	Electricity Authority using the simple OM approach in accordance with ACM0002.
Any comment:	-

Data / Parameter:	**Carbon Emission Factor of Coal, Naphtha**
Data unit:	tCO_2/TJ
Description:	Emission factor of coal which has been identified as the baseline scenario fuel This data also is used as an input for calculating the fugitive CH_4 emissions occurring in the absence of the project activity
Source of data used:	Carbon Emission Factor for Coal: Table 2.3 - India specific CO_2 emission coefficients, India's first National Communication to the United Nations Carbon Emission Factor for Naphtha: Table 1.2 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook
Value applied:	Refer Annex – 6
Justification of the choice of data or description of measurement methods and procedures actually applied :	As per AM0029, the fuel emission coefficient is to be determined based on national average fuel data if available. Accordingly we have used the data available in India's first national communication to the United Nations for our calculations where available, otherwise IPCC default values have been used.
Any comment:	-

Data / Parameter:	**Oxidation Factor of Coal, Naphtha**
Data unit:	-
Description:	Oxidation factor of coal which has been identified as the baseline scenario fuel This data is used as an input for calculating the fugitive CH_4 emissions occurring in the absence of the project activity
Source of data used:	Table 1.6 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual
Value applied:	Refer Annex 6
Justification of the choice of data or description of measurement methods and procedures actually applied :	Only IPCC default values are available.
Any comment:	-

Data / Parameter:	η_{BL} ***– Efficiency of coal fired power generating stations***
Data unit:	-
Description:	Energy efficiency of coal fired power plant which has been identified as the baseline scenario
Source of data used:	Calculated value based on fuel consumption, NCV of coal and electricity generation data for coal fired power stations published in the CEA General Review for western region.

Value applied:	38%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority is Government of India undertaking mandated to publish information on performance of power sector in India by the Electricity Act 2003.
Any comment:	-

<table>
<tr><td>Data / Parameter:</td><td>Coal consumption in coal fired Power plants in the western region</td></tr>
<tr><td>Data unit:</td><td>Million tonnes (MT)</td></tr>
<tr><td>Description:</td><td>This data is used as an input for calculating the Energy efficiency of coal fired power plants</td></tr>
<tr><td>Source of data used:</td><td>CEA CO2 Baseline database</td></tr>
<tr><td>Value applied:</td><td>
<table>
<tr><th>Coal fired stations</th><th>Coal consumption (million tones)</th></tr>
<tr><td>Khaperkheda TPS</td><td>4,909</td></tr>
<tr><td>Sanjay Gandhi TPS</td><td>4,047</td></tr>
<tr><td>Vindhyachal STPS</td><td>10,860</td></tr>
<tr><td>Wanakbori TPS</td><td>7,404</td></tr>
<tr><td>Gandhinagar TPS</td><td>3,158</td></tr>
<tr><td>Chandrapur</td><td>12,234</td></tr>
</table>
</td></tr>
<tr><td>Justification of the choice of data or description of measurement methods and procedures actually applied :</td><td>Central Electricity Authority is Government of India undertaking mandated to publish information on performance of power sector in India by the Electricity Act 2003. All data is from CEA thermal review 2004 - 05 and CEA general review 2005 – 06.</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

Data / Parameter:	**Calorific values of Coal, Natural Gas and Naphtha**
Data unit:	kCal/Kg or kCal/SCM
Description:	This data is used as an input for calculating the Energy efficiency of coal fired power plants and the fugitive CH4 emissions occurring in the absence of the project activity
Source of data used:	NCV of Coal – Table 6.3, CEA General Review 2006 NCV of Natural Gas and Naphtha: CEA Data on Petroleum fuels used by various Gas Turbines and Diesel Engine Power Plants in India in 2003-04
Value applied:	Refer Annex – 6
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority is Government of India undertaking mandated to publish information on performance of power sector in India by the Electricity Act 2003.
Any comment:	-

Data / Parameter:	**Electricity Generation from Coal fired power plants in the Western Region**
Data unit:	GWh
Description:	This data is used as an input for calculating the Energy efficiency of coal fired power plants
Source of data used:	CEA CO2 baseline database
Value applied:	see table below
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority is Government of India undertaking mandated to publish information on performance of power sector in India by the Electricity Act 2003. In order to facilitate baseline emissions relating to electricity generation activities, CEA has published a database of CO2 emission factors for all the regional grids in India. This database also contains information on electricity generation from all major thermal power stations in the country.
Any comment:	-

Coal fired stations	Gross generation
	GWh
Khaperkheda TPS	6,289
Sanjay Gandhi TPS	5,460
Vindhyachal STPS	17,831
Wanakbori TPS	10,883
Gandhinagar TPS	4,986
Chandrapur	15,925

Data / Parameter:	**Carbon Emission Factor of Natural Gas ($EF_{CO2,f,y}$)**
Data unit:	tCO_2/GJ
Description:	The CO_2 emission factor per unit of energy of natural gas in year 'y'
Source of data used:	IPCC default value has been applied (Source: Chapter-2 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	56.1 tCO_2/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	As there are no national data available for the emission factor of the fuel used, default value based on Table 2.2 of 2006 IPCC Guidelines for National Greenhouse Gas Inventories has been applied.
Any comment:	-

Data / Parameter:	**Oxidation Factor of Natural Gas ($OXID_f$)**
Data unit:	-
Description:	Oxidation factor of natural gas
Source of data used:	IPCC default value has been applied (Source: Chapter-2 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	0.995
Justification of the choice of data or description of measurement methods	As there are no national data available, IPCC default value based on is considered

and procedures actually applied :	
Any comment:	-

Data / Parameter:	**Station Heat Rate of the Project activity**
Data unit:	kCal/kWh
Description:	Station Heat Rate has been used to calculate the quantity of Natural Gas consumption associated with the expected electricity generations from the project activity. This data is used as an input for calculating Project Emissions.
Source of data used:	From EPC contractor (value based on gross calorific value 2000 kCal/kWh; based on net calorific value 1,800 kCal/kWh)
Value applied:	1,800 kCal/kWh
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	-

Data / Parameter:	**CO2 emissions from Build Margin Power plants in the western region**
Data unit:	tCO2e
Description:	This data is used as an input for calculating the fugitive CH4 emissions occurring in the absence of the project activity
Source of data used:	CEA CO2 Baseline database
Value applied:	Refer Annex – 6
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority is Government of India undertaking mandated to publish information on performance of power sector in India by the Electricity Act 2003. In order to facilitate baseline emissions relating to electricity generation activities, CEA has published a database of CO2 emission factors for all the regional grids in India. This database also contains information on CO2 emissions of all major thermal power stations in the country.
Any comment:	

B.6.3 Ex-ante calculation of emission reductions:

>> The emission reductions ***ERy*** by the project activity during a given year *y* is:

ERy = BEy – PEy – LEy

Where:

ER_y : emissions reductions in year y (t CO_2e)

BE_y : emissions in the baseline scenario in year y (t CO_2e)

PE_y : emissions in the project scenario in year y (t CO_2e)

LE_y : leakage in year y (t CO_2e)

Baseline Emissions:

Baseline Emissions: $BE_y = EG_{PJ,y} * EF_{BL,CO_2,y}$

EGy = Annual expected net electricity generation from the project activity

= Gross electricity generation – Auxiliary Power Consumption @ 3% of gross generation

= (155 MW x 85% (PLF) x 8,760 (hours))*0.97

= 1,119,506 MWh

$EF_{BL,CO2,y}$ = 0.630 tCO2e/MWh. (refer section B.6.1)

Baseline Emissions = 1,119,506 MWh x 0.630 tCO2e/MWh = 705,289 tCO2e

Project Emissions (PEy):

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

$FC_{f,y}$ = Annual fuel consumption by the project activity

= Annual Electricity Generation x Gross Station Heat Rate / Calorific Value of Natural Gas

= 1,119,506 (MWh) x 1800 (MCal/MWh) / 8581 (MCal/1000SCM)

= 242.10 (Mcum)

$COEF_{f,y}$ = 2,005.42 tCO2e/Mcum (refer section B.6.1)

Project Emissions = 242.10 (Mcum) x 2,005.42 (tCO2e/Mcum) = 485,507 tCO2e

Leakage

Leakage: Ly = 28,906 tCO2e (Please refer Annex - 6 for details of Leakage calculations)

Emission Reductions = 705,289 tCO2e - 485,507 tCO2e - 28,906 tCO2e
= 190,876 tCO2e

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

>> A summary of the ex-ante estimation of emission reductions for all years of the crediting period has been presented in the table below.

Year	Estimation of project activity emissions (tCO_2e)	Estimation of baseline emissions (tCO_2e)	Estimation of leakage (tCO_2e)	Estimation of overall emission reductions (tCO_2e)
Year 1	485,507	705,289	28,906	190,876
Year 2	485,507	705,289	28,906	190,876
Year 3	485,507	705,289	28,906	190,876
Year 4	485,507	705,289	28,906	190,876
Year 5	485,507	705,289	28,906	190,876
Year 6	485,507	705,289	28,906	190,876
Year 7	485,507	705,289	28,906	190,876
Year 8	485,507	705,289	28,906	190,876
Year 9	485,507	705,289	28,906	190,876
Year 10	485,507	705,289	28,906	190,876
Total (tCO_2e)	**48,55,070**	**70,52,890**	**2,89,060**	**19,08,760**

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

>> **Approved monitoring methodology AM0029 "Monitoring Methodology for Grid Connected Electricity Generation Plants using Natural Gas".**

Reference: Available on http://cdm.unfccc.int, Version 01.1 dated 19 May, 2006.

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.

B.7.1 Data and parameters monitored:

Data / Parameter:	**$FC_{f,y}$**
Data unit:	m^3 (cum)
Description:	Total volume of natural gas combusted in the project plant in year y
Source of data to be used:	From plant fuel consumption log data
Value of data applied for the purpose of calculating expected emission reductions in section B.5	242.10 mcum
Description of measurement methods and procedures to be applied:	Measured daily, data being stored electronically. Monthly joint reading by BPL and ESTL stored in paper form
QA/QC procedures to be applied:	The meters will be calibrated as per the standard procedures and documents for the same will be maintained throughout. Refer Annex 4 more details.
Any comment:	100% of data will be monitored.

Data / Parameter:	**NCV_f**
Data unit:	kCal/SCM
Description:	The net calorific value (energy content) per volume unit of natural gas in year 'y' as determined from ESTL data
Source of data to be used:	From ESTL
Value of data applied for the purpose of calculating expected emission reductions in section B.5	8581
Description of measurement methods and procedures to be applied:	Measured by ESTL using chromatograph, the value will be supplied by ESTL once in a shift in electronic form.

QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	The data will be archived electronically

Data / Parameter:	**$EF_{co2,f,y}$**
Data unit:	tCO2e/GJ
Description:	CO2 Emission Factor of Natural Gas
Source of data to be used:	IPCC default values for Carbon Emission Factor (15.3 tC/tJ)
Value of data applied for the purpose of calculating expected emission reductions in section B.6	**$EF_{co2,f,y}$** = 15.3 x 44/12 = 56.10 tCO2e/tJ
Description of measurement methods and procedures to be applied:	Default values for Carbon Emission Factor of Natural Gas as per Table 1.2 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook has been considered. This is also in conformity with the recommendations of the GHG inventory information report submitted by India's Initial National Communication (Chapter 2) where in it is mentioned that in the case of petroleum products and natural gas, the use of default emissions would be fairly accurate due to relatively low variation in quality of these fuels across the globe, as compared to coal. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	Carbon Emission factor of natural gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

Data / Parameter:	**$OXID_f$**
Data unit:	
Description:	Oxidation Factor of Natural Gas
Source of data to be used:	IPCC
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.995
Description of measurement methods and procedures to be applied:	Default values as per Table 1.6 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual has been considered. This is also in conformity with the recommendations of the GHG inventory information report submitted by India's Initial National Communication (Chapter 2) where in it is mentioned that in the case of petroleum products and natural gas, the use of default emissions would be fairly accurate due to relatively low variation in quality of these fuels across the globe, as compared

	to coal. This data will be recorded annually based on latest IPCC information available and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	Oxidation factor of natural gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

Data / Parameter:	$EG_{PJ,y}$
Data unit:	MWh/ year
Description:	Net electricity generation in the project plant during the year y
Source of data to be used:	From the electronic meters installed at the project site.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1,119,506 MWh (Based on a PLF of 85% and auxiliary power consumption of 3%)
Description of measurement methods and procedures to be applied:	As per actual meter readings. The daily reading will be archived electronically. Monthly joint meter reading will be archived in paper form.
QA/QC procedures to be applied:	The meters will be calibrated as per the standard procedures and documents for the same will be maintained throughout. Refer Annex 4 for more details.
Any comment:	-

Data / Parameter:	$EF_{BM,y}$
Data unit:	tCO_2/MWh
Description:	Build Margin Emission factor for western grid
Source of data used:	"CO_2 Baseline Database for Indian Power Sector" published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO_2 Baseline Database for Indian Power Sector" version 2 dated 21 June 2007 available on website of Central Electricity Authority (http://cea.nic.in)
Value of data applied for the purpose of calculating expected emission reductions in section B.5	0.630
Description of measurement methods and procedures to be applied:	Build Margin Emission Factor will be taken from the CO2 baseline database published by CEA. In case the CEA database is not updated, the project proponent will calculate the Build Margin number using CEA data. This data will be computed annually based on latest available information and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to	No additional QA/QC procedures are planned.

be applied:	
Any comment:	-

Data / Parameter:	***$EF_{BL,upstream,CH4}$***
Data unit:	tCO2e/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation
Source of data to be used:	CEA CO2 baseline database or calculated value based CEA data in case the database is not updated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	11.3 tCO2e/MWh
Description of measurement methods and procedures to be applied:	$EF_{BL,upstream,CH4}$ is calculated for power plants included in the Build Margin, inline with the baseline emission factor selection. 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 or tCO2e/MWh) will also be determined ex-post. This data will be computed annually based on latest available information and will be archived in electronic/paper form. Archived data will be kept up to two years from the end of crediting period or the last issuance, which ever occurs later.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	

B.7.2 Description of the monitoring plan:

>> The Monitoring and Verification (M&V) procedures define a project-specific standard against which the project's performance (i.e. GHG reductions) and conformance with all relevant criteria will be monitored and verified. It includes developing suitable data collection methods and data interpretation techniques for monitoring and verification of GHG emissions with specific focus on technical performance parameters. It also allows scope for review, scrutiny and benchmarking of all this information against reports pertaining to M & V protocols. The monitoring plan is prepared considering in following areas of Project Activity:

1. Establishing and maintaining the appropriate monitoring systems for consumption of NG and electricity generated by the proposed project.
2. Quality control at Project Activity and measurements.
3. Assigning monitoring responsibilities to personnel.
4. Data storage and filing system.

The detailed monitoring plan for the proposed CDM project activity has been presented in Annex-4.

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)

>> The baseline study and application of baseline methodology was completed on 13/07/2007.

PricewaterhouseCoopers (P) Limited has assisted the project proponent in determining the application of baseline methodology for the identified CDM project.

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:

>> Date of start (as per Engineering, Procurement & Construction contract): 20/05/2004

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

>> 20 years.

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:

>> Not applicable.

C.2.1.2. Length of the first crediting period:

>> Not applicable.

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>> The 1st year of crediting will start from the date of registration of this project activity and has been assumed to be 01/09/2007.

C.2.2.2. Length:

>> 10 years 0 months 0 days

SECTION D. Environmental impacts

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

>> The proposed project is Phase-I of the 500 MW natural gas based power plant. The environmental clearances for the project have been obtained from the regulatory authorities based on rapid environmental impact assessment (EIA) study for this proposed expansion. The EIA study was conducted during the period March to June 2004.

The major findings from this EIA study as related to the construction of CCPP are presented below:

i) Land Use: Since the land is developed by HADA and maintained by GIDC for industrial use, no major agricultural or residential activity is present in the vicinity. Thus, land use pattern will not be altered except during construction & erection phase, which may change land use pattern temporarily.

ii) River Water Resources: Water required for cooling purpose will be drawn from Tapi estuary for cooling and for other purposes, raw water will be used. Wastewater from the cooling tower will be treated to meet the standards applicable.

iii) Ground Water Resources: No demand on ground water is considered and therefore, no impact on it is anticipated.

iv) Air Quality: Air quality survey was carried out to establish baseline status of various gaseous pollutants. The impact on air quality has been quantified using Gaussian Dispersion Model and it reveals that, the impact of proposed project on Ambient Air Quality is minimum.

v) Noise: Existing noise levels in the region were measured during the survey. Use of machines and equipment with latest technology will not generate noise beyond permissible standards. Therefore the noise impact of the proposed plant on environment will be negligible. Green belt developed in the factory premises will further alternate the noise levels.

vi) Ecology: Since the area is developed by HADA for industrial use, no clustered trees are found in the vicinity. Hence there will not be any kind of deforestation. No reserved forest, sanctuary or ecologically sensitive area is present within 20 km radius area of the site. No rare or endangered species of flora and fauna are present in the immediate vicinity. Thus, there will not be any adverse impact on flora and fauna.

Environment Management Plan (EMP) for the power plant has been designed for efficient functioning of the plant so as to minimize the adverse environmental effects. The EMP recommends measures for impact minimisation during both the construction and operations phase of the project.

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 project activity uses natural gas in preference over other fossil fuels such as coal and hence results in lower GHG emissions. Other air and liquid pollutants are minimal. There are no significant solid wastes such as fly ash. The EIA study revealed that there are no significant environmental impacts.

SECTION E. Stakeholders' comments

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

>> Local stakeholder consultation meeting to discuss stakeholder concerns on proposed Clean Development Mechanism (CDM) projects of Essar Steel Limited / Bhander Power Limited at Hazira was conducted on 20.09.2006, 11.00 am at Conference room in the HRD centre, Essar Power Limited, Hazira, Gujarat state, India. An open 15-day prior notice for information to all stake-holders was provided.

The meeting was attended by the villagers from nearby villages of Hazira and Matafalia; employees from Essar Power; Bhander Power; Essar Steel living in the nearby township;

Essar representative, Mr T S Bhatt gave a presentation to the members on the following:

- About Bhander Power Limited and their activities,
- About The Clean Development Mechanism under Kyoto Protocol.
- About BPL's 155 MW wind NG based CCPP; its technology and other details.
- On the climate change, global warming and the effect of the same to the entire world.
- On Kyoto protocol and the objective of the same and how this was formed and the necessity to do the CDM.
- What is important in CDM and the objectives of the same.
- What is the contribution from BPL towards this project.
- How this helps the local public
- What are the environmental benefits we can get by going for NG

Once the presentation was over the stake holders were requested to share their experience and doubts about this project.

E.2. Summary of the comments received:

>> A summary of local stakeholders' concerns, questions and comments is presented in the table below:

Stakeholder concern / question / comment	Replies by "Essar Steel Limited"/ "Bhander Power Limited"
Would there be any increase of pollution load?	The project does not use fossil fuels such as coal, diesel, naphtha, etc., and hence will not add to pollution load.
What would be the impacts of the CDM project on the local fauna?	The green belt development that has been developed on previously existing saline land has resulted in many more birds and fauna to come to this area.
Which technology is used in this project?	All the equipment for the project is sourced from highly reputed manufactures across the globe. Hitachi, Japan under license agreement from GE USA has manufactured gas turbine generator. Deltak, USA has manufactured the HRSG. Siemens has manufactured the steam turbine. Siemens India has supplied the state of the art control system for the plant. Most of the balance of plant items are manufactured and supplied by local companies in

Stakeholder concern / question / comment	Replies by "Essar Steel Limited"/ "Bhander Power Limited"
	India.
How does CO_2 increase in the environment from power generation?	Fuels used for power generation contain carbon, which gets converted to CO_2. Fuels with more hydrogen do not result in such emission.
What type of employment will be created?	The project employs local labour during construction phase and operation phase.
What are the contributions of the project activity to local sustainable development?	The project would be lead to sustainable development around the project area by contributing to the development of local economy and create jobs and employment in and around the project site and reducing pollution load on the environment.
Will the employees be imparted special training?	The plant is operated with local technicians and engineers. Required training for enhancing competency has been imparted to the employees.

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

>> The answers to queries from the local stake-holders provided during the meeting. No comments were received from any local stake-holders during days after this meeting. The minutes of the meeting and the proceedings have been recorded and signed of by the Chairman.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Essar Steel Limited
Street/P.O.Box:	11, Kesavrao Kakade Marg
Building:	19th Floor, Essar House
City:	Mumbai
State/Region:	Maharashtra
Postfix/ZIP:	400034
Country:	India
Telephone:	+91-22-66601100
FAX:	+91-22-24952929
E-Mail:	kvbreddy@essar.com
URL:	www.essar.com
Represented by:	
Title:	Associate Director
Salutation:	Mr.
Last Name:	Reddy
Middle Name:	V B
First Name:	K
Department:	Chairman Secretariat
Mobile:	+91-9819730605
Direct FAX:	+91-22-24952929
Direct tel:	+91-22-66601914
Personal E-Mail:	kvbreddy@essar.com

Organization:	Bhander Power Limited
Street/P.O.Box:	11, Kesavrao Kakade Marg
Building:	5th Floor, Essar House
City:	Mumbai
State/Region:	Maharashtra
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Country:	India
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FAX:	+91-22-24954787
E-Mail:	aksrivastava@essar.com
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Represented by:	
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Salutation:	Mr.
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Middle Name:	K
First Name:	A
Department:	
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Direct FAX:	+91-22-24954787
Direct tel:	+91-22-66601551
Personal E-Mail:	aksrivastava@essar.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

The total cost of the project activity is about INR 2900 million with 30% equity and 70% debt from Indian Financial Institutions components.

No public funding has been used for the proposed CDM project activity.

Annex 3

BASELINE INFORMATION

Grid Emission Factors[26]:

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

Simple Operating Margin

	Western Grid (tCO2e/GWh)
Simple Operating Margin - 2003-04	990.31
Simple Operating Margin - 2004-05	1,011.94
Simple Operating Margin - 2005-06	993.37
Average Operating Margin of last three years	998.55

Build Margin

	Western Grid (tCO2e/GWh)
Build Margin	630..01

Combined Margin Calculations

	Western Grid (tCO2e/GWh)
Combined Margin	814.28

[26] Baseline Carbon Dioxide Emissions from Power Sector, Baseline Carbon Dioxide Emission Database Version 2.0 dated 21 June 2007 on http://cea.nic.in

CALCULATION OF ENERGY EFFICIENCY OF COAL BASED POWER PLANT

Coal fired stations	Coal consumption	NCV	Input Energy	Gross generation	Output Energy	Efficiency
	Million Tonnes	kCal/kg	GJ	GWh	GJ	
Khaperkheda TPS	4,909	3,755	77,176,520	6,289	22,640,400	29.34%
Sanjay Gandhi TPS	4,047	3,755	63,624,643	5,460	19,656,000	30.89%
Vindhyachal STPS	10,860	3,755	170,734,773	17,831	64,191,600	37.60%
Wanakbori TPS	7,404	3,755	116,401,497	10,883	39,178,800	33.66%
Gandhinagar TPS	3,158	3,755	49,648,289	4,986	17,949,600	36.15%
Chandrapur	12,234	3,755	192,336,024	15,925	57,330,000	29.81%
					Average	**32.91%**

Conversion factor used: 1kWh = 3.6 MJ

As can be seen the lowest energy efficiency is 29.34% and highest is 37.6% with average value at 32.91%. In order to be conservative we have used a value of 38%.

Annex 4

MONITORING INFORMATION

Monitoring Plan for CDM activity:
The general conditions set out in this monitoring plan for metering, recording, meter inspections, test & checking; and communication shall be applicable for both electrical energy and natural gas, where relevant and applicable.

Data for Calculation of CER:
The Emission Reductions (ER_y) will be calculated based on calculations for Project Emissions (PE_y); Baseline Emissions (BE_y) and Leakage (LE_y)

$$ER_y = BE_y - PE_y - LE_y$$

The parameters that would be monitored for PE_y are:

1. **Natural Gas Consumption ($FC_{f,y}$):** Based on daily meter readings for the total natural gas consumption archived electronically
2. **Net Calorific Value of Natural Gas ($NCV_{f,y}$):** Based on daily arithmetic average value of net calorific value, archived electronically

The parameters that would be monitored for BE_y are:

3. **Net Electricity Generation (EG_y):** Based on daily meter readings of the gross electricity generated and the auxiliary consumption. The following Formula is used for arriving at the Net Electricity Generated:

Net Electricity Generated	=	Gross Electricity Generated by Gas Turbine Generator	+	Gross Electricity Generated by Steam Turbine Generator	-	Auxiliary Consumption of 155 MW gas fired power plant

4. **Emission Factor based on Build Margin ($EF_{BM,y}$) for the western regional grid of India:** This value would be taken from the database published annually by Central Electric Authority (CEA) on their website http://cea.nic.in. In case for any particular year CEA does not publish the value then $EF_{BM,y}$ will be calculated based on the electricity generation and other relevant data published by CEA.

I. Monitoring for Net Electricity Generation (EG_y):

Metering Plan

The delivered energy (electricity) is metered by the Project proponent at the following locations:

1. Gas Turbine Generators
   - Main meter - high Voltage side of the step up transformer using a 0.2 class energy meter
   - Check meter– high voltage side of the step up transformer using a 0.2 class energy meter
2. Steam Turbine Generator
   - Main meter - high Voltage side of the step up transformer using a 0.2 class energy meter
   - Check meter - high Voltage side of the step up transformer using a 0.2 class energy meter

Metering equipments shall be electronic meters. The Gross electricity generation measurements from Gas Turbine Generator and Steam Turbine Generator are done using respective main meters and check meters. Sum of Gross generation from the Gas Turbine Generator and the Steam Turbine Generator shall be the gross generation from the plant. The metering equipment shall be maintained in accordance with electricity standards.

3. Auxiliary Consumption
   - Main meter – C1 incomer at 6.6kV level using a 0.2 class energy meter
   - Main meter – C2 incomer at 6.6kV level using a 0.2 class energy meter
   - Main meter – SST 3 incomer at 6.6kV level using a 0.2 class energy meter

Auxiliary consumption for the power station is met by import of electricity through the station transformer. The measurement of electricity imported for auxiliary consumption are done using the main meter of accuracy class 0.2 installed at three numbers of 6.6kV level feeders for supplying auxiliary load. The sum of the energy meter reading of the three 6.6kV feeders gives the total auxiliary consumption. The metering equipment shall be maintained in accordance with electricity standards.

The meter readings are recorded from the energy meters manually on a daily basis (00.00 Hrs every day) and are archived in electronic format, monthly. The joint meter reading indicating the net energy exported in the month are recorded and signed by BPL and ESTL at the end of each month. The joint meter readings are archived in paper form.

Meter Test / Checking for Energy Meter Reading (Gross Energy Generated):

Scheduled testing of meters

The energy meter shall be tested for accuracy at least once in every 5 years against an accepted laboratory standard meter in accordance with electricity standards by an accredited third party. The meters shall be deemed to be working satisfactory if the errors are within specifications for meters of 0.2 accuracy class. The consumption registered by the main meter will hold well as long as the error in the meters is within the permissible limits.

The meters will be tested / calibrated on site by an accredited third party. The testing / calibration will be synchronized with scheduled maintenance of the plant whenever practical. Whenever the calibration of the meter does not coincide with the scheduled maintenance of the plant, the meter will be made offline for the duration of the test / calibration. Under such circumstances, when the main meter is made offline for test / calibration, the reading recorded by the check meter will be used for calculations. If the check meter is made offline for test / calibration, the reading recorded by the main meter will be used for calculations.

Comparison of Main meter and check meter readings

If the recorded reading of the main meter and the check meter differ by more than 0.5 % in a month, both the meters will be tested and calibrated on site immediately, one after the other. During the calibration / test, if the main meter readings are found to be within the permissible limits of error, then the readings recorded by the main meter will hold good. If the main meter reading are found to be beyond the permissible limits of error, and the check meter is working within the permissible limits of error, then the reading recorded by check meter will be considered for calculations since last calibration / test or verification date whichever is later, up to the current calibration / test. If during the calibration and tests, both the main meter and check meter are found to be beyond permissible limits of error, then correction will be applied to the reading registered by the main meter to arrive at the correct reading of energy supplied for the period beginning of the month up to that particular day.

Meter Test / Checking for Energy Meter Reading (Auxiliary Consumption):

The energy meter shall be tested for accuracy at least once in five years against an accepted laboratory standard meter in accordance with electricity standards by an accredited third party. The meters shall be deemed to be working satisfactory if the errors are within specifications for meters of 0.2 accuracy class. The consumption registered by the meter will hold well as long as the error in the meters is within the permissible limits. If during the calibration and test the meter is found to be beyond permissible limits of error, then correction will be applied to the reading registered by the meter to arrive at the correct reading of energy for the period starting from the last calibration / test or verification date whichever is later, up to the current calibration / test.

Missing Data:

In case of any missing data due to a meter being taken out of service for calibration/ testing, last 3 months average shall be used to close the gap. The statistical techniques used shall conform to BIS or any other relevant international standards.

II. Monitoring for Natural Gas Consumption ($FC_{f,y}$):

Metering Plan

The natural gas consumed is metered by the Project Proponent at the following locations

1. Main meter - Located at the Gas Conditioning Skid
2. Check meter - Located at the inlet of Gas Turbine

The meter readings are displayed in the plant DCS and is recorded from the DCS manually on daily basis (00.00 Hrs every day) in electronic format and are archived monthly in electronic format. The joint meter reading indicating the natural gas consumed for the month are recorded and signed by BPL and ESTL at the end of each month. The joint meter readings are archived in paper form.

Metering Equipment for Natural Gas Consumption:

Metering equipments consists of differential pressure type meters along with differential pressure transmitters, pressure transmitters for pressure measurement and RTD for temperature measurements. Changes in specific gravity reading are also considered in the computation of the natural gas flow, updated manually once in every shift. The Natural Gas Consumption metering is done using a main meter and a check meter. Both the meters are of AGA-3/API14.3 standard. The meters shall be installed and owned by the Project proponent. The metering equipment shall be maintained in accordance with relevant standards.

Meter Test / Checking for Natural Gas Meter Reading (Natural Gas Consumed):

The natural gas meter shall be tested for accuracy at least once in six months against an accepted laboratory standard meter in accordance with prescribed standards. The meters shall be deemed to be working satisfactory if the errors are within specifications for meters of AGA-3/API14.3. The consumption registered by the main meter will hold well as long as the error in the meters is within the permissible limits.

If the recorded reading of the main meter and the check meter differ by more than one percent in a month, both the meters will be tested and calibrated immediately one after the other. During the calibration / test, if the main meter reading is found to be within the permissible limits of error, then the readings recorded by the main meter will hold good. If the main meter reading are found to be beyond the permissible limits of error, and the check meter is working within the permissible limits of error, then the reading recorded by check meter will be considered for calculations since last calibration / test or verification whichever is later, up to the current calibration / test. If during the calibration and tests, both the main meter and check meter are found to be beyond permissible limits of error, then correction will be applied to the reading registered by the main meter to arrive at the correct reading of natural gas consumed for the period starting from the last calibration / test or verification whichever is later, up to the current calibration / test.

The testing / calibration will be synchronized with scheduled maintenance of the plant whenever practical. Whenever the calibration of the meter does not coincide with the scheduled maintenance of the plant, the meter will be made offline for the duration of the test / calibration. Under such circumstances, when the main meter is made offline for test / calibration, the reading recorded by the check meter will be used for calculations. If the check meter is made offline for test / calibration, the reading recorded by the main meter will be used for calculations.

Calibration Procedure:

If any of the meter is found to be not working or faulty, the meter will be taken out of service and calibrated / tested immediately. If one of the meters has been taken out for calibration / test, the natural gas consumption recorded by the other meter shall be recorded and used for calculations, during the time duration for calibration / test.

Calibration / test of the natural gas meters shall be done by BPL against master laboratory meter owned by the project participant. The master laboratory meter shall in turn be calibrated by an accredited third party as per a reputed & relevant international standard. All the calibration certificates including that of the master laboratory meter shall be maintained by the project participant.

Missing Data:

In case of any missing data, last 3 months average shall be used to close the gap. The statistical techniques used shall conform to BIS or any other relevant international standards.

III. Monitoring for Net Calorific Value of Natural Gas ($NCV_{f,y}$):

Metering Plan

The net calorific value of natural gas is measured by ESTL, the fuel supplier to the project. The sampling is done at the fuel supplier's end once in a shift (Total three times in a day) and the analysis is done using offline chromatograph located at ESTL laboratory.

The fuel analysis done is uploaded in the intranet from ESTL laboratory. The fuel analysis readings are displayed in the plant intranet terminal available at the control room. The net calorific value and the specific gravity of the natural gas is recorded from the intranet manually once in a shift.

The arithmetic average of the net calorific value for the three shifts in a day is considered as the calorific value of the natural gas for the day and the arithmetic average of net calorific value for all days in a month is considered as the net calorific value of the natural gas consumed for that month.

The monthly arithmetic average value of net calorific value is archived electronically.

Metering Equipment for Natural Gas Net Calorific Value:

Net calorific value of the natural gas is measured by ESTL using an offline chromatograph. The metering equipment is owned by ESTL and shall be maintained in accordance with relevant standards.

Meter Test / Checking for Chromatograph Reading (Net Calorific Value):

The chromatograph shall be tested for accuracy and calibrated at least once in four months against an accepted standard gas in accordance with prescribed standards. The composition of the standard gas is provided by the gas supplier. The calibration certificates of the chromatograph shall be maintained by the project participant.

Missing Data:

In case of any missing data, last 3 months average shall be used to close the gap. The statistical techniques used shall conform to BIS or any other relevant international standards.

IV. Internal Audit Plan:

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 collected, the process followed and the quality control and assurance measures. They shall report any non-conformity to the Head – 500 MW CCPP, BPL, Hazira and he shall take appropriate steps to rectify the non-conformity.

The following documents shall be made available to the internal audit team:

1. Copy of the registered PDD
2. Copy of the Power Purchase Agreement

3. Electricity meter reading recorded daily & archived monthly in electronic form
4. Natural gas consumption meter reading recorded daily & archived monthly in electronic form
5. Net calorific value reading archived monthly in electronic form
6. Joint monthly electricity meter reading archived in paper from
7. Joint monthly natural gas consumption reading archived in paper form
8. Natural Gas Logbook maintained in the control room indicating NCV
9. Daily data recorded in primary data collection forms for the quarter
10. Copy of invoices raised by BPL on ESTL
11. Copy of monthly MIS reports
12. Meter Calibration record

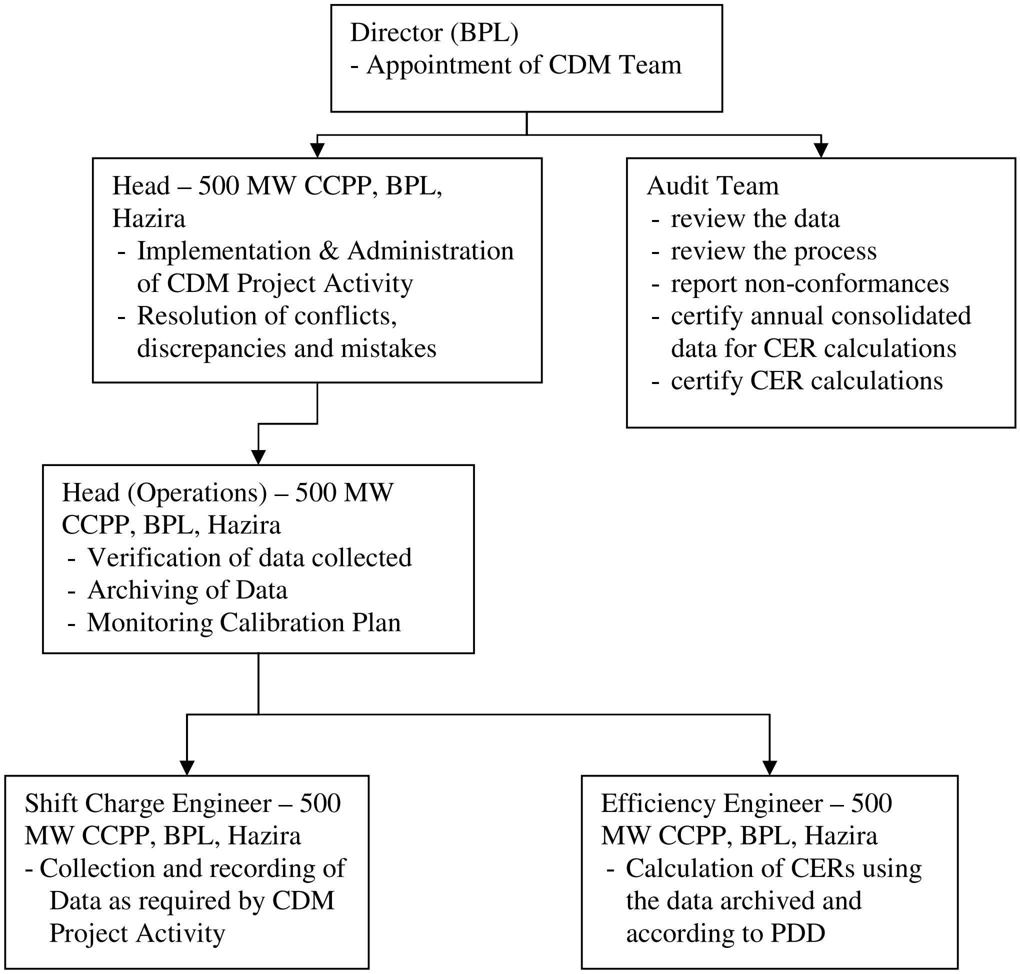
The internal audit team shall also certify the annual consolidated data for the verification of CER. The team shall also certify the calculations for arriving at actual CER.

Verification:

The quantitative details indicating the net exported electrical energy, natural gas consumed and the net calorific value audited by the internal audit team constituted for the purpose shall be used, for verification of the CERs. Further, the joint energy meter reading jointly signed by ESTL and BPL and the invoices raised by BPL on ESTL shall be the base audit document for verification protocol.

V. Team for CDM Monitoring Plan Implementation:

The organization structure and division of responsibilities for implementation of CDM project activity is described below:



Director (BPL) shall be responsible for appointment of CDM team for the implementation of CDM project activity. Any change in the CDM team composition or responsibilities shall be notified by Director (BPL).

The shift charge engineer of BPL shall be responsible for collecting and recording all the data as required by the PDD and monitoring plan.

Head of Operation, 500 MW CCPP, BPL, Hazira is responsible for verifying the data collected and recorded on a day to day basis and archiving of the data. He is also responsible for ensuring the calibration of all the instruments are done according to the schedule and the requirement of monitoring plan.

Efficiency Engineer, 500 MW CCPP, BPL, Hazira shall be responsible for calculation of CERs from the archived data and according to PDD of the CDM Project Activity.

Head – 500 MW CCPP, BPL, Hazira is responsible for the overall implementation & administration of the monitoring plan. Conflicts, Discrepancies, Mistakes etc in relation to the monitoring plan of the CDM project activity shall be referred to Head – 500 MW CCPP, BPL, Hazira for resolution and his resolution in this regard shall be final and binding.

An audit team shall be constituted consisting of Head of Department – C&I and Head of the Department – Electrical Maintenance. The audit team shall meet once in three months (Quarterly) at 500 MW CCPP, BPL, Hazira to review the data, process and report non-conformances with PDD, monitoring plan and Quality Control Measures.

VI. Data Recording Procedure:

All the relevant data as per the registered PDD and the CDM monitoring plan recorded daily (00.00 Hrs every day) in Primary Data Collection Form with form number BPOL/24HR/PH-1 and is signed by the on-duty shift charge engineer (SCE). The data recorded is archived at the end of every month in electronic format by Head (Operations) – 500 MW CCPP, BPL, Hazira in form number BPOL / PH-1/PR/00 HR.

The monthly joint meter reading indicating the energy exported for the month is recorded and signed at 00.00 Hrs on 1st of every month by the on duty shift charge engineers of 500 MW CCPP, BPL and MRSS, ESTL, in form number BPOL/JMR/ELECT/PH-1. The joint meter reading will be verified and signed by Head (Operations) – 500 MW CCPP, BPL and Head – MRSS, ESTL.

The monthly joint meter reading indicating the natural gas consumption for the month is recorded and signed at 00.00 Hrs on 1st of every month by the on duty shift charge engineers of 500 MW CCPP, BPL and Production Planning Control, ESTL, in form number BPOL/JMR/NG/PH-1. The joint meter reading will be verified and signed by Head (Operations) – 500 MW CCPP, BPL and Head – Production Planning Control, ESTL.

Any modification / changes required on the above forms for recording data shall be authorised by Head – 500 MW CCPP, BPL, Hazira.

- - - - -

Annex 5

Project Location Map

Project Site

Annex 6

LEAKAGE CALCULATIONS

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

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 t CO_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 t CO_2e

$$LE_{CH4,y} = \lfloor FC_y.NCV_y.EF_{NG,upstream,CH4} - EG_{PJ,y}.EF_{BL,upstream,CH4} \rfloor .GWP_{CH4}$$

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 tCH_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

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

where:

$EF_{BL,upstream,CH4}$ 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

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 CH_4 per MJ fuel produced

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

CO_2 emissions from LNG

Where applicable, CO_2 emissions from fuel combustion / electricity consumption associated with the liquefaction, transportation, re-gasification and compression of LNG into a natural gas transmission or distribution system ($LE_{LNG,CO2,y}$) should be estimated by multiplying the quantity of natural gas combusted in the project with an appropriate emission factor, as follows:

$$LE_{LNG,CO_2,y} = FC_y . EF_{CO_2,upstream,LNG}$$

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

FC_y Quantity of natural gas 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

Upstream fugitive emissions on account of use of natural gas by the project activity

Sr. No	Fugitive Emissions due to gas usage	Unit of measurement	Formula for calculation	Value
1	Fugitive CH4 emission factor	tCH4/PJ		160.00
2	Annual Gas consumption (based on 50% NG of the total NG consumption)	Mcum		121.05
3	Calorific Value	kCal/SCM		8581
4	Calorific Value	TJ/Mcum	= (3) x 4.1868/10^3	35.93
5	Energy content in Gas consumed	PJ	= (2) x (4)/10^3	4.35
6	Fugitive CH4 emissions	tCH4	= (1) x (5)	695.82
7	Equivalent CO2 emissions	tCO2e	= (6) x 21	14,612

Upstream fugitive emissions on account of use of LNG by the project activity

Sr. No	Fugitive Emissions due to gas usage	Unit of measurement	Formula for calculation	Value
1	Fugitive CH4 emission factor	tCO2/TJ		6.0
2	Annual LNG consumption (based on 50% NG of the total NG consumption)	Mcum		121.05
3	Calorific Value	kCal/SCM		8865
4	Calorific Value	TJ/Mcum	= (3) x 4.1868/10^3	37.12
5	Energy content in Gas consumed	PJ	= (2) x (4)/10^3	4.493
6	Leakage due to LNG	tCO2e	= (6) x (1)	26,957

Upstream fugitive emission occurring in the absence of the project activity

Upstream fugitive emission occurring in the absence of the project activity = $EG_{PJ,y}$ x $EF_{BL,upstream,CH4}$

= 1,119.506 GWh x 11.3 tCO2e (refer the next page for calculations of $EF_{BL,upstream,CH4}$)
= 12,663 tCO2e

Leakage = 15,472 tCO2e + 28,543 tCO2e – 12,663 tCO2e = 26,687 tCO2e

Calculation of $EF_{BL,upstream,CH4}$ is shown in the table below:

	Emissions	Emission factor	Fuel consumption		Fugitive emission factor		Fugitive emissions
	tCO2e	tCO2e/1000 t or Mcum	1000 t	PJ	tCH4/1000t	tCH4/PJ	tCO2e
Coal	16,972,449	1,476	11,498		0.8		193,163
Lignite	2,210,454	1,186	1,863		0.8		31,301
Natural gas	2,922,245	1,905		52		160	175,902
Naphtha	212,985	2,587		4		4.1	332
Total							400,698

Net electricity generation (Million kWh) corresponding to build margin from CEA Database	35,425

Fugitive emission factor (tCO2e/Million kWh)	**11.3**

Data sources:

NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2005	STATE	FUEL 1	FUEL 2	2005-06 Absolute Emissions t CO2
GANDHI NAGAR	5	17-Mar-98	210	GUJARAT	COAL	OIL	1,665,437
WANAKBORI	7	31-Dec-98	210	GUJARAT	COAL	OIL	1,733,936
SANJAY GANDHI	3	28-Feb-99	210	MADHYA PRADESH	COAL	OIL	1,769,463
SANJAY GANDHI	4	23-Nov-99	210	MADHYA PRADESH	COAL	OIL	1,688,076
VINDH_CHAL STPS	7	03-Mar-99	500	MADHYA PRADESH	COAL	OIL	3,582,250
VINDH_CHAL STPS	8	26-Feb-00	500	MADHYA PRADESH	COAL	OIL	3,727,637
K_KHEDA II	3	31-May-00	210	MAHARASHTRA	COAL	OIL	1,274,887
K_KHEDA II	4	07-Jan-01	210	MAHARASHTRA	COAL	OIL	1,530,764
Total Coal							16,972,449
SURAT LIG.	1	16-Jan-00	125	GUJARAT	LIGN	OIL	968,287
SURAT LIG.	2	06-Nov-99	125	GUJARAT	LIGN	OIL	1,004,072
AKRIMOTA LIG	1	31-Mar-05	125	GUJARAT	LIGN	OIL	205,356
AKRIMOTA LIG	2	19-Dec-05	125	GUJARAT	LIGN	OIL	32,739
Total Lignite							2,210,454
HAZIRA CCCP	1	30-Sep-01	52	GUJARAT	GAS	n/a	161,812
HAZIRA CCCP	2	30-Sep-01	52	GUJARAT	GAS	n/a	163,507
HAZIRA CCCP	3	30-Sep-01	52.1	GUJARAT	GAS	n/a	167,712
DHUVARAN CCPP	1	04-Jun-03	67.9	GUJARAT	GAS	n/a	187,333
DHUVARAN CCPP	2	22-Sep-03	38	GUJARAT	GAS	n/a	104,840

DHUVARAN CCPP	3	17-Mar-06	72	GUJARAT	GAS	n/a	7,619
G.I.P.C.L. GT	6	18-Nov-97	54	GUJARAT	GAS	NAPT	166,219
G.T.E. CORP.	1	01-Apr-98	135	GUJARAT	GAS	NAPT	414,110
G.T.E. CORP.	2	01-Apr-98	135	GUJARAT	GAS	NAPT	435,992
G.T.E. CORP.	3	14-Feb-98	135	GUJARAT	GAS	NAPT	416,174
G.T.E. CORP.	4	13-Oct-98	250	GUJARAT	GAS	NAPT	696,927
Total Natural Gas							2,922,245
RELIANCE ENERGY	1	14-Aug-99	48	GOA	NAPT	n/a	212,985
Total Naphtha							212,985

Source: CEA Database, Selection of Western Region Thermal Plants that are in the build margin

Type of FUEL	Net Calorific Value (TJ/ 103 tonnes or TJ/Mcum)	Carbon Emission Factor (t C/ TJ)	Fraction of Carbon Oxidised Oxidation Factor	Emission Coefficient (tCO2/ 103 tonnes or tCO2/Mcum)	Density (kg/Lt)	Emission factor (tCO2/1000 t or tCO2/Mcum)
Coal	15.72	26.13	0.98	1,476	1.00	1,476
Lignite	11.40	28.95	0.98	1,186	1.00	1,186
Natural Gas	34.12	15.30	1.00	1,905	1.00	1,905
Naphtha	46.89	20.00	0.99	3,404	0.76	2,587

Source:
NCV of Coal, Lignite - Table 6.3 of CEA General Review
NCV of Natural Gas and Naphtha: CEA Data on Petroleum fuels used by various Gas Turbines and Diesel Engine Power Plants in India in 2003-04
Carbon Emission Factor for Coal and Lignite: Table 2.3 - India specific CO2 emission coefficients, India's first National Communication to the United Nations
Carbon Emission Factor for Natural Gas and Naphtha: Table 1.2 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook
Carbon Oxidation Factor: Table 1.6 Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual