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

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Annexes

SECTION A. General description of project activity

A.1 Title of the project activity:

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"351.43 MW Natural Gas Based Combined Cycle Power Plant at Hazira, Gujarat".

Version – 03

Dated: 27/12/2012

A.2. Description of the project activity:

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Purpose of the project activity:

The proposed project activity is a Natural Gas based Combined Cycle Power plant (CCPP) at Hazira, Gujarat by Gujarat State Energy Generation Limited (GSEGL). GSEGL is a special purpose vehicle[1] (SPV) formed by GSPC (Gujarat State Petroleum Corporation) to generate power in Gujarat.

GSEGL has obtained the necessary approvals from the regulatory authorities to set up the power plant. The project activity will operate partly on natural gas and partly on Liquefied Natural Gas (LNG) which are cleaner fuels leading to lower Carbon Dioxide (GHG) emissions, compared to the other power plants in the region operating on other fuels like coal / lignite / oil / naphtha. The total requirement of natural gas/ LNG for the proposed 351.43 MW CCPP will be about 541.01[2] Million SCM/year. The project activity receives the gas[3] through a separate pipeline from GSPC, and water is pumped from the Tapi river. GSEGL and GUVNL (Gujarat Urja Vikas Nigam Limited) have entered into a 'Power Purchase Agreement (PPA)[4] under which GSEGL intends to sell the generation capacity and supply of electricity in bulk to GUVNL to the extent of 351.43 MW capacity in aggregate.

The project employs state of the art technology with estimated project life of 23 years. The proposed project activity comprises one (1) Gas Turbine Generator, one (1) Heat recovery Steam Generators (HRSG) and one (1) Steam Turbine Generator (STG). The station heat rate (SHR) of the project activity has been considered as 1850 kCal/kWh.

The power generated from this project activity is evacuated to the nearby 220 kV switchyard of GETCO (Gujarat Energy Transmission Corporation Limited). The spatial extent of the project boundary includes the equipment that form a part of the CCPP at GSEGL's Hazira. The equipments that form part of the project boundary are:

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[1] http://www.gspcgroup.com/company_detail.php?CID=5

[2] Calculated as per the Assumptions: PLF= 80%; operating hours = 8760; normative station heat rate of 1850 kCal / kWh (as per CERC Tariff order dated 26.3.2004; Net calorific value at 8422 kCal/SCM (as per DPR)

[3] At present GSEGL has a fuel supply contract with GSPCL, GSEGL expects that in future, the natural gas for this project activity may be sourced from a different supplier (s) as well.

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

S.No	Equipment	Specifications
1.	GTG	One Gas Turbine Generator (“**GTG**”), GE Frame 109 FA, Manufactured by BHEL under license from GE Energy.
2.	STG	Steam Turbine Generator (STG) manufactured by BHEL, model being KN turbine, K30-16+N30-2X5.0.
3.	HRSG	One Heat Recovery Steam Generator (“**HRSG**”) of triple pressure, natural circulation and unfired type boiler manufactured by BHEL.

Electricity generated by the project activity will be fed into the Gujarat state electricity grid, which forms part of the NEWNE grid (comprising of North, east, west and north-eastern regions of India). This will help in bridging the gap between demand and supply of electricity as presented in the table below[5] in the State of Gujarat.

DEMAND SUPPLY POSITION								
	Peak Demand	**Peak Met**	**Peak Deficit / Surplus (MW)**	**(Peak Deficit / Surplus %)**	**Energy Requirement (MU)**	**Energy Availability (MU)**	**Energy Deficit /Surplus (MU)**	**Energy Deficit/ Surplus (%)**
End of 9th Five year Plan	8005	6700	-1305	-16.3	53693	47530	-6163	-11.5
2002-03	8641	7336	-1305	-15.1	60175	53316	-6859	-11.4
2003-04	9820	7204	-2616	-26.6	57171	50292	-6879	-12
2004-05	10162	7578	-2584	-25.4	59681	52724	-6957	-11.7
2005-06	9783	7610	-2173	-22.2	57137	52436	-4701	-8.2
2006-07	11619	8110	-3509	-30.2	62464	54083	-8381	-13.4

Being a gas based grid-connected power plant, the project activity caters to the base load power requirement of the Western region.

The main purpose of the project activity is to generate electricity to cater the base load requirements in the NEWNE grid..

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.

Pre project scenario:

Since the project activity is a new grid connection power plant, the pre-project scenario entails generation of power from existing or proposed new power plants connected to the NEWNE (North East Western North Eastern) regional grid. The power plant is proposed to supply the power to Gujarat Urja Vikas Nigam Limited (GUVNL).

The pre-project scenario will include generation of power from existing or proposed new power plants connected to the NEWNE regional grid. Alternatives to the project activity include power generation based on domestic coal, imported coal; lignite; natural gas, naphtha, nuclear energy; renewable sources of energy (like wind, hydro). The other alternatives included capacity additions to existing

[5] http://www.cea.nic.in/archives/plg/power_glance/oct08.pdf

power plants in the region or establishing new inter-connections with the other regional grid. All these alternatives have been discussed in detail in section B.4 of the PDD.

Project Scenario:

In the project scenario natural gas will be utilized as fuel for power generation in combined cycle power plant. The Gas turbine plants operate on the Brayton cycle. In this cycle a compressor is used 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 to produce electricity. The exhaust from the gas turbine will then be utilized in boiler to generate steam which will be utilized in steam turbine to generate electricity. In addition to the main plant equipment, auxiliary cooling water system, condenser cooling water system, electrical systems, evacuation of power, etc., will also be installed as a part of the project.

Baseline scenario:

The applied baseline methodology AM0029 version 03 is based on 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"* for determining the baseline scenario. Based on this, all the plausible baseline scenarios were evaluated based on investment analysis using levelized cost of generation as a parameter for identifying the "economically most attractive baseline scenario alternative".

In case of the subject project activity, this was ascertained and found to be a power plant (s) based on **Coal as fuel with supercritical technology** would have been the most plausible baseline scenario for the project activity. The details on technology, efficiency, operating lifetime for various fuel/ technology options have been discussed in detail in Section B.4.

Reduction of greenhouse gas emissions:

The project activity avoids requirement to purchase power from the NEWNE grid of India that is predominantly supplied with coal/ lignite based power plants, and reduces requirement of its power generation in the grid, thereby avoiding emission of Green House Gases ("**GHGs**").

Contribution of the project activity to sustainable development:

The National CDM Authority ("**NCDMA"**) in India has approved the project and granted host country approval. The contribution of this project activity towards sustainable development as per the four indicators prescribed by NCDMA in India i.e., Ministry of Environment and Forests ("**MoEF**") is presented below based on which the NCDMA has granted host Government approval to the project activity.

Social well being

- 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.
- The land on which the CCPP is constructed is already a procured land and thus free from habitation and cultivation.
- This project will help in strengthening the local grid of the state electricity utility by increasing the availability of electrical energy in that region.

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 Certified Emission Reductions ("**CERs**") and through transaction of such CERs with Annex I Parties, the project activity would bring in additional revenue to India.

Environmental well being

- Liquefied natural gas, which is the main fuel for this project activity, is a clean fuel without any constituent to generate any particulate matter in flue gas.
- There would not be any emission of sulphur dioxide as LNG does not have any sulphur content. The NOx content in the flue gas will be low due to use of low NOx dry type hybrid burners in the gas turbines.
- This project activity will also meet the ambient air concentration limits stipulated by the Central Pollution Control Board by appropriately designing the height of the HRSG stack.
- There will be reduction in GHGs emission (mainly CO2) into the atmosphere per unit of electricity generation.
- The site is not in the vicinity of any national parks, wildlife sanctuaries, tropical forests and biosphere reserves.

Technological well being

- The project activity is a natural gas based combined cycle power plant and would result in improved power generation efficiency as compared to an open cycle CCGT or coal or lignite based thermal power plant of similar capacity.

GSEGL is committed to sustainable development. GSEGL will contribute 2% of the net revenues accrued from the sale of Certified Emission Reductions (CERs) on an annual basis towards achieving the sustainable development goals. If the activity undertaken involves capital expenditure exceeding the minimum requirement of 2%, the additional expenditure made would be set off against the requirements for the subsequent years. Such expenditure would be made within one year after the realization of revenues from the sale of the CERs.

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)
India (Host Party)	Gujarat State Energy Generation Limited (GSEGL) - Public Entity	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

>>
Village Hazira (Mora), Taluka Choryasi, District Surat, Gujarat, India

A.4.1.1. Host Party(ies):

>>
India

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

>>

Gujarat

A.4.1.3. City/Town/Community etc:

>>

Hazira (Mora)

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

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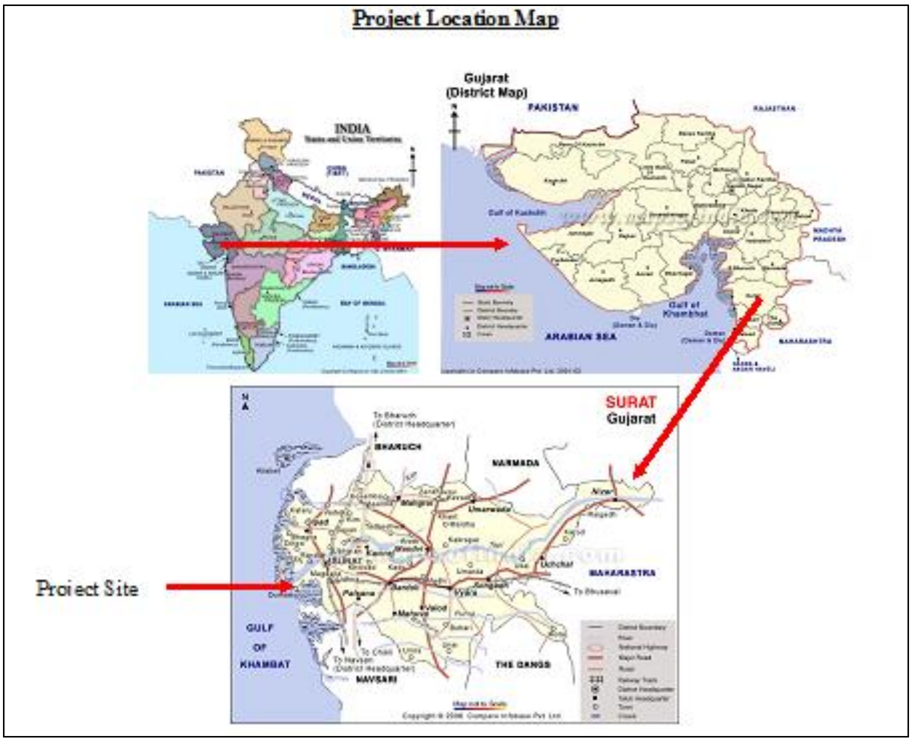
The project activity is located on a 15 hectares of land that is available by the side of the existing plant which is being utilized for installation of proposed 351.43 MW CCPP at Hazira at Longitude[6]: 72°39'42.04"E; Latitude: 21°10'0.22"N and Altitude: 5.65 Meters (Above Mean Sea Level). This area 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 below.



[6] http://wikimapia.org#lat=21.1667303&lon=72.6616779&z=19&l=0&m=b

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

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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:

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Pre-project Scenario

The project activity is a new grid connected power plant, the pre-project scenario entails generation of power from existing or proposed new power plants connected to the NEWNE regional grid.

The various plausible alternatives to the project activity have been discussed and analysed in detail in Section B.4.

Project Activity:

There is no technology transfer in this project activity. The project employs state of the art technology with estimated project life of 23 years.

The one unit of 351.43MW Combined Cycle Power plant consist of one (1) gas turbine generator (GTG), one (1) matching triple pressure heat recovery steam generator (HRSG) and one (1) steam turbine generator (STG). Bharat Heavy Electrical Ltd. (BHEL) has been the choice to supply the project on EPC basis and would use GE technology in gas turbine of 9 FA machine.

The energy facility engages a highly efficient turbine engine, fuel by clean burning natural gas to drive an electrical generator. Exhaust from the gas turbine is utilized to operate a heat recovery steam generator for turning water into steam, used to turn a steam turbine connected to another generator-thus producing additional electrical energy. Complete exploitation of the fuel to extract maximum of energy is possible through this process.

To minimize water consumption and vapour plumes, the project utilizes an air cooled condenser in lieu of evaporative cooling that allows the facility to operate with less water than normally required. Natural gas is being piped to the facility from a duct interconnection with the Gujarat State Petronet Limited (here after referred as "GSPL", the gas transporter for this project and a Gujarat State Petroleum Corporation (GSPC) group company) pipeline system.

Gas Turbine Generator (GTG):

The gas turbine generator is rated about 261.68 MVA at 15^0C ambient air temperature, 0.85 PF lag, 15 kV, 3000 rpm, 50 Hz. The gas turbine block consists of a multistage compressor and a turbine and is of hydrogen cooled type. The main features are:

- Multiple axial type compressor
- The modulating compressor inlet guide vanes providing 17 to 1 pressure ratio.
- The compressor inlet consisting of a filter house with self cleaning pulse jet air filters, ducting and silencer
- The airfoil shaped compressor rotor blades to compress air efficiently at high blade tip velocities

- The rotor blades inserted into broached slots located around periphery of each wheel and wheel portion of the stub staff
- Three major subassemblies of casing, the inlet casing, the compressor casing and the compressor discharge casing. All casings are horizontally spilt for ease of handling and maintenance
- The blow off lines are provided down stream of compressor stationary blades
- The lube oil pumps, lube oil reservoir and lube oil coolers form the lubrication oil system.
- The exhaust system consists of exhaust silencer and ducting.

Heat Recovery Steam Generator (HRSG):

The main features of the HRSG are as follows

- Triple pressure, natural circulation heat recovery steam generator
- Horizontal type
- Self supporting stack
- Condensate preheater for recovery of thermal energy to maximum extent along with superheater, evaporator and economic sections.
- Internal thermal insulation with platforms and ladders
- Feed water and steam sampling arrangements.
- High pressure and low pressure bypass systems with 100% HRSG capacity.

Steam Turbine Generator (STG):

The steam turbine generator is rated about 151.765 MVA at 15^0C ambient air temperature, 0.85 PF lag, 15 kV, 3000 rpm, 50 Hz. It is of air cooled type. The main features of the STG are as follows:

- Reheat and condensing type steam turbine.
- Set of emergency stop and control valves.
- Lube oil, control oil system, jacking oil system, governing system, protection system and gland stealing system
- Surface type condenser
- Two no. of mechanical vacuum pumps
- Two no. of condensate extraction pumps.

Apart from this, the project activity will be having the following auxiliary systems :

- Feed Water System
- Cycle Chemical Dosing System
- Compressed Air System
- Air Conditioning System
- Ventilation System
- Plant Water System
- Cooling Water System
- Fire Protection System
- Effluent treatment system etc.

The age of the equipments installed under the project activity is 0 years (new) and the lifetime is 23 years. The installed capacity is 351.43 MW[7] and will not alter in the crediting period or project life. The plant load factor is estimated to be 80%. The gross heat rate of the plant would be 1850 kcal/kWh. The power plant will deliver net 2462.82 GWH/year exportable electricity which will be sold entirely to Gujarat Urja Vikas Nigam Ltd. (GUVNL) on two part tariff basis. The plant will consume 541.018MSCM per year of natural gas which will be delivered by GSPL. GSEGL and GSPC have signed a long term fuel supply agreement. The monitoring for the project activity constitutes the electricity exported, quantity of natural gas consumed and its Net Calorific Value (NCV).

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.

The green house gases emitted from project activity would include CO_2 emissions due to On-site fuel combustion.) The CO_2 emissions due to processing and transportation of fuel outside the project boundary are being accounted for as leakage emissions. Also, please refer to the section B.3 of the document for GHG emission sources as a result of the project activity.

Please refer Section B.7.2 and Annex 4 Monitoring information for details of the monitoring plan and the location of the monitoring equipments.

Table 1 Specifications of the major equipments and Parameters:

Parameter	**Description**
GT Generation Capacity at Site Conditions	222.43 MW[9]
ST Generation Capacity at Site Conditions	129.00 MW[10]
Total capacity at Site Conditions	351.43 MW
Power factor	0.85
GTG and STG Frequency	50 Hz
Steam Pressure	133 kg/cm^2, HP inlet steam pressure, 34 kg/cm^2 IP inlet steam pressure, 4.8 kg/cm^2 LP inlet steam pressure.
NO_X Level	25 PPMVD at 15% O_2 in Flue Gas
Equipments	**Description**

[7] Plant capacity at site conditions are referred from BHEL offer.

[8] Natural gas consumption by the plant is estimated considering the volume as LNG as Zero

[9] Bid documents mention the GTG capacity as 222.43 MW, the name plate capacity of the STG installed GTG installed by BHEL has a capacity of 222.39 MW.

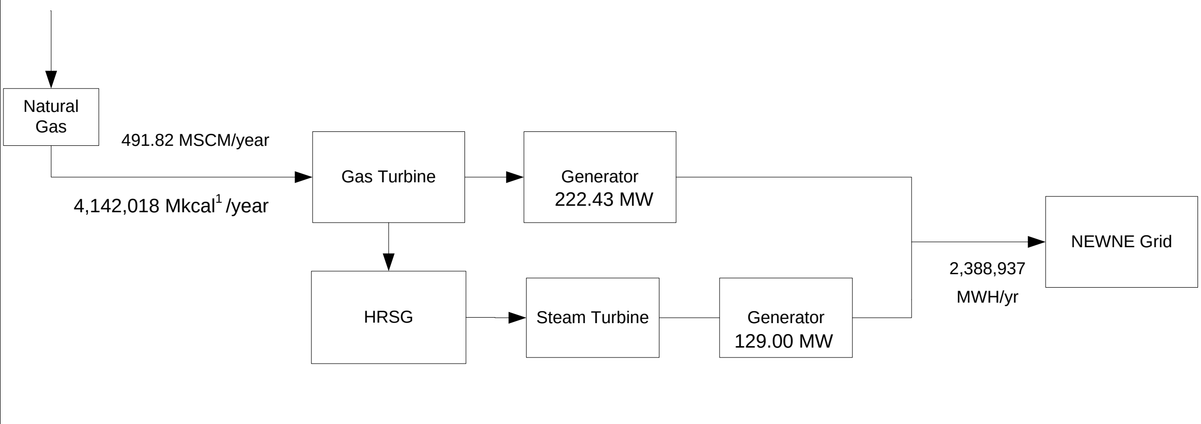
[10] The bid documents mention the STG capacity as 129.00 MW; the name plate capacity of the STG installed is 190 MVA (161.5 MW at 0.85 PF). However, the generation of the STG will be governed by the amount of flue-gas generated by the operation of the GT, and based on the design, the generation of the STG will be close to the capacity provided in the bid document (129.00 MW).

GT Cooling	Evaporator Air Induced system
GT Burners	Dry Low NO_X burners
Gas Turbine Parameters	General Electric Make, Frame MS9351(FA), Single Shaft

Site Conditions

SI.No	Item	Value
1	Ambient Conditions	
	a) Dry bulb temperature	33°C
	b) Relative Humidity	70%
	c) Design Wet bulb temperature	28°C
2	Altitude above mean sea level	5.65m
3	Frequency	50Hz
4	Power factor	0.85(lagging)
5	Fuel Supply temperature	8 °C
6	Average ambient pressure	1012 milli bar

The energy and mass flow diagram of the project is provided below;



[1] Considering the calorific value of the gas 8,421.70 Kcal/SCM

<u>Baseline scenario:</u>

Since the project activity is the installation of a new grid-connected power plant, the baseline scenario is that the electricity delivered to the grid by the project activity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources.

The applied baseline methodology AM0029 version 03 is based on 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" for determining the baseline scenario. Based on this, all the plausible baseline scenarios were evaluated based on investment analysis using levelized cost of generation as a parameter for identifying the "economically most attractive baseline scenario alternative". In case of the subject project activity, this was ascertained as found to be a power plant (s) based on **Coal** as fuel with supercritical technology.

The details on technology, efficiency, operating lifetime for various fuel/ technology options have been discussed in detail in Section B.4.

The green house gases in the baseline scenario (power generation using coal as fuel (with supercritical technology) and associated Fuel processing and transportation) would emit higher CO_2.

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

>> The estimated emission reductions over the 10 year fixed crediting period would be 8,859,440 **tCO_{2e}** as per details on annual emission reductions provided below.

Years	**Annual estimation of emission reductions in tonnes of CO_2 e**
1	885,944
2	885,944
3	885,944
4	885,944
5	885,944
6	885,944
7	885,944
8	885,944
9	885,944
10	885,944
Total estimated reductions (tonnes of CO_2 e**)**	8,859,440
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tonnes of CO_2e**)**	885,944

A.4.5. Public funding of the project activity:

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There is no[11] Official Development Assistance ("**ODA**") involved in development of the proposed CDM project activity.

[11] Financing for this project is done thru 70% debt and 30% equity. Loan sanction letter from REC is available for verification by the DOE

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:

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Approved baseline methodology AM0029 (version 03 EB39) 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**".

Approved monitoring methodology AM0029 (version 03 EB39) for "Grid Connected Electricity Generation Plants using Non-Renewable and Less GHG Intensive Fuel" has been used to list primary parameters to be monitored during the crediting period of the project activity.

The project activity also refers to the "Tools to calculate the emission factor for an electricity system" (Version 02.2.1, EB 63).

The project activity also refers to the "Tool for the demonstration and assessment of additionality" (Version 06, EB 65)

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[12] electricity generation plant that supplies electricity to GUVNL. The fuel 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 NEWNE[13] 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 Electricity Authority of India http://cea.nic.in.

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

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

Natural Gas Availability:

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[14] ("**MMSCMD**"). The main producers of natural gas are Oil & Natural Gas Corporation Ltd. ("**ONGC**"), Oil India Limited ("**OIL**") and JVs of Tapti, Panna-Mukta and Ravva[15]. Out of the total production of around 87 MMSCMD, after internal consumption, extraction of Liquefied Petroleum Gas ("**LPG**") and unavoidable flaring, around 74 MMSCMD[16] is available for sale to various consumers.

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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[17].

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 Gas Authority of India Ltd ("**GAIL**"). 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.

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

There have been discoveries in Krishna-Godavari (KG) basin[18] by – Reliance Industries Limited ("**RIL**"), GSPCL and ONGC. RIL is expected to produce about 29.2 Billion Cubic Meter[19] ("**BCM**") per year (equivalent to 80 MMSCMD). RIL is also constructing a cross country natural gas pipeline connecting eastern coast of India in Andhra Pradesh and Bharuch in Gujarat. State-owned Gujarat State Petroleum Corporation Limited ("**GSPCL**") has struck gas in the Krishna Godavari basin, off

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[14] http://petroleum.nic.in/ng.htm

[15] http://petroleum.nic.in/ng.htm

[16] http://petroleum.nic.in/ng.htm

[17] http://petroleum.nic.in/ng.htm

[18] http://www.financialexpress.com/news/reliance-ipps-under-bses-may-use-krishnagodavari-gas/68427/

http://www.infraline.com/ong/NaturalGas/Pricing/GasPricingJVGas-10Dec06.pdf

[19] http://www.business-standard.com/india/news/more-d-6-gas-may-dryspot-lng-in-months/361130/

Andhra Pradesh coast in the Bay of Bengal. This additional indigenous gas can be brought to Gujarat through the pipeline.

LNG Re-gasification terminals:

The installed terminals include– Dahej (5 Million Metric Tonnes Per Annum ("**MMTPA**") equivalent to 7142.85 Million Standard Cubic Meter (MSCM) / Year), Hazira (2.5 MMTPA equivalent to 3571.4 MSCM/Year) on west coast.

Under implementation: Dabhol (RGPPL) (2.5 MMTPA equivalent to 3571.4 MSCM/Year), Dahej Expansion (5 Million Metric Tonnes Per Annum ("**MMTPA**") equivalent to 7142.85 Million Standard Cubic Meter (MSCM) / Year), Kochi (2.5 MMTPA equivalent to 3571.4 MSCM/Year).

Proposed LNG Regas – Dahej Expansion (5 MMTPA), Mangalore (5 MMTPA equivalent to 3571.4 MSCM/Year), Ennore (2.5 MMTPA equivalent to 3571.4 MSCM/Year).

Amongst all the NG/RLNG supply sources discussed above the likely future supply sources in the western region are as follows:

Supply Source (Western Region)	Units (MMTPA/Year)	Units (MSCM/Year)
Reliance Industries Limited (RIL) – domestic natural gas (East- West gas distribution network)	-	29200
Dahej Expansion – imported re-gasified LNG[20]	5	7142.85
Dhabol - – imported re-gasified LNG	2.5	3571.429
Total	**-**	**39914.29**

In addition to the above discussion please find below the natural gas demand and the corresponding power generation in the western region of India for the future natural gas based power stations as included in the 11th five year plan (2007 - 2012)[21] of Government of India.

Plant	Capacity (MW)	Generation in a year (GWh or Million Units)	Fuel consumption in a year (MSCM/Year)
Ratanagiri (Dhabol) JV	740.00	5185.92	1035.63
Dhuvran ST	219.00	1534.75	306.49
Utran CCPP	374.57	2624.99	524.21
GSEG Hazira	351.43	2462.82	491.83
Pipavav JV CCGT	702.00	4919.62	982.45
Sugen Torrent	1128.00	7905.02	1578.63
Total	3515.00	24633.12	4919.24

It is evident from the table above that for proposed generation of 24633.12 million units of power the estimated natural gas demand is expected at 4919.24Million SCM/ year[22].

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[20] http://www.petronetlng.com/news1/detailedratingrationalefinal.pdf (company profile page 3 of 11).

[21] http://www.cea.nic.in/archives/plg/monitor_11plan/jul09.pdf

[22] Assumptions: PLF= 80%; operating hours = 8760; normative station heat rate of 1850 kCal / kWh (as per CERC Tariff order dated 26.3.2004; net calorific value at 8422 kCal/SCM (as per DPR)

This further demonstrates that natural gas demand by power plants in the Western Region as included in the 11th five year plan is 4919.24 MSCM per year as against the availability of 39914.29 MSCM per year. GESGL's Phase I (156.1 MW) gas based power plant is not a part of the 11th five year plan. Hence the fuel requirement for this plant is calculated separately. The total gas requirement including this plant is 5137.70 MSCM/year. This clarifies the sufficient availability of natural gas in the region and for future natural gas based power capacity additions, comparable in size to the project activity. The detailed spread sheet on the gas supply and demand in the western region has been submitted to the DOE during validation.

It is apparent from the statistics presented above that the future gas supply in the western region would be adequate for meeting the fuel requirement of the gas based power stations included in the 11th five year plan by Government of India. This data further substantiates that natural gas is sufficiently available in the region and 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.

Thus gas quantities required for fulfilling this gas based economy vision are expected to be available in the envisaged time frame.

From the above it can be seen that natural gas is available to the project activity and natural gas is sufficiently available in the region. It can also be seen that 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.

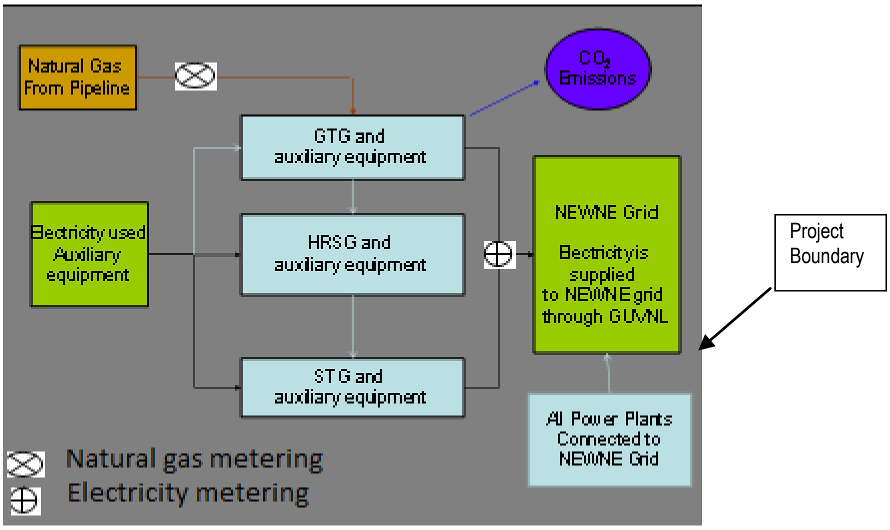
From the above paragraphs, it can be seen that the project activity satisfies all the applicability conditions of AM0029, version - 03.

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 351.43 MW CCPP at GSEGL’s Hazira site as listed below and all power plants connected physically to the baseline grid as defined in “Tool to calculate emission factor for an electricity system” (Version - 2.0, EB - 50).

The equipments that form part of the project boundary are:

1. Gas Turbine Generator (GTG)
2. Steam Turbine Generator (STG)
3. 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).
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.

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.

6. Establishing a Natural Gas fired power plant but with a technology different from the project activity

An important fact to note here is that the GSEGL power plant had been designed for catering to the base load requirement. It is connected to the Western regional electricity grid, which now forms[23] part of NEWNE electricity grid.

On analysing the installed capacities of thermal power plants connected to the western grid and commissioned since 1998[24], the pattern for fuel distribution emerges as follows:

Fuel	Installed capacity (MW)	Percentage of total installed capacity of 7718.78 MW
Coal	3760	48.71%
Lignite	500	6.48%
Gas	851	11.02%
Nuclear	1080	13.99%
Naphtha	1528	19.80%

Further referring to the approved baseline methodology AM0029, version – 03 that recommends the following guideline in order to identify the plausible baseline scenario:

"The identification of alternative baseline scenarios should include all possible realistic and credible alternatives that provide outputs or services comparable with the proposed CDM project activity (including the proposed project activity without CDM benefits) i.e., all type of power plants that could be constructed as alternative to the project activity within the grid boundary (as defined in "Tool to calculate emission factor for an electricity system, version -2.0, EB - 50*)".*

The project activity involves installation of a gas based Combined Cycle Power Plant ("CCPP") of capacity 351.43 MW by GSEGL. The power generated will be supplied to GUVNL under a long term power purchase agreement (PPA)[25].

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

Alternative	Potential alternative conditions	Permitted by regulations
1.	**Power generation using natural gas as fuel and combined cycle technology without CDM revenues (Project activity)**	Yes
2.	**Power generation using NG as fuel but with technologies other than the project activity**	
2.1	*Power generation in Open (simple) Cycle Mode*	Yes
2.2	*Power generation in Co-generation mode*	Yes
3.	**Power generation technologies using energy sources other than natural gas.**	
3.1	*Power generation using coal as fuel with subcritical*	Yes

[23] CEA Version 04 mentions, grid integration has happened in August 2006

[24] http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htmversion 3.0, dated 15 Dec 2007.

25 The PPA has been provided to the DOE during validation

Alternative	Potential alternative conditions	Permitted by regulations
	technology	
3.2	*Power generation using coal as fuel with super-critical technology (using Imported coal)*	Yes
3.3	*Power generation using lignite as fuel*	Yes
3.4	*Power generation using naphtha as fuel*	Yes
3.5	*Power generation using run-of-river[26] hydro power*	Yes
3.6	*Power generation using nuclear power*	Yes
3.7	*Power generation using wind energy*	Yes
4.	**Import of electricity from connected grids, including the possibility of new interconnections**	Yes

The candidate project is a utility scale 351.43 MW gas based power plant. As can be observed in the CEA database version – 7, there are no solar/diesel power plants of comparable capacity. Hence, electricity generation based on solar/diesel technology has not been considered as a baseline alternative.

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 calculated in INR/kWh has been considered the most suitable financial indicator as to determine the economically most attractive baseline scenario alternative.

The detailed assumptions made for levelized tariff calculations of all fuel/ technology options are presented in Annex 7.

Alternative 1: Power generation using natural gas as fuel and combined cycle technology without CDM revenues (Project activity)

The project activity involves generation of grid connected power in a combined cycle power plant (CCPP) using natural gas/ Re-gasified LNG as fuels. The CCPP comprises of 1 GTG, 1 HRSG and 1 STG. Without considering any CDM revenue for this project activity, it can be a baseline scenario.

Technology: 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 (@ 25-35 %[27] 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 boiler generates steam by capturing heat form the turbine exhaust. These boilers are known as heat recovery steam generators ("**HRSG**").

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

[27] Chapter 22.2.4, Page 7, Book authored by Dennis Snow titled "Plant Engineers Reference book" http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpjrYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result

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 to around 50 %[28]). As per Tool to determine the remaining lifetime of equipment, Annex 15 of EB 50 meeting report, the default technical lifetime of gas turbine is 200,000 hours ≈ 23 years, whereas of boiler is 25 years. Hence the default technical lifetime of gas based power plant is 23 years conservatively.

Alternative 2: Power generation using NG as fuel but with technologies other than the project activity

Apar from the combined cycle mode of operation (as discussed above), the power, using natural gas as fuel, can be generated in following two ways.

2.1) Power generation in Open (simple) Cycle mode

For an Open (simple) cycle mode of operation, the turbine's energy conversion efficiency typically remains low (@ 25-35 %)[29]. As the option has lower system efficiency in comparison to the power generation using Combined Cycle mode of operation, it is not a realistic and credible alternative to the project proponent to opt for open cycle mode of operation for high capacities such as the case of project activity. Therefore this alternative is not a plausible baseline scenario.

2.2) Power generation in Co-generation cycle mode

The Cogeneration mode of operation is mainly used to provide electricity and steam for industrial facility and the project activity's purpose is to deliver only the power to the grid. Thus, this option does not deliver the similar output/ services comparable to the project activity. Hence, this is also not a credible and realistic alternative for the Project Proponent and therefore this alternative is not plausible baseline scenario.

Alternative 3: Power generation technologies using energy sources other than natural gas.

3.1) Power generation using coal as fuel with sub-critical technology

Technology: The power generation technology (sub-critical) using coal/lignite as fuel is most commonly available in size of 200 MW/210MW/250MW sets and 500 MW and above sets[30]. Thus for comparison with project activity a coal based power plant of 400 MW (2 units of 200 MW each) has been considered. Fossil fuel-fired (coal) power plants use steam to provide the mechanical power to electrical generators. Pressurized high temperature steam 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

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28 http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpjrYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result

29 Chapter 22.2.4, Page 7, Book authored by Dennis Snow titled "Plant Engineers Reference book" http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpjrYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result

30 http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf ; Page (10 of 72)

in Air Pre-heaters. 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 around 25% to 30%[31]. As per Tool to determine the remaining lifetime of equipment, Annex 15 of EB 50 meeting report, the default technical lifetime of boiler and steam turbine is 25 years. Hence the default technical lifetime of coal based power plant is 25 years. This has been considered as one of the plausible baseline alternatives.

3.2) *<u>Power generation using coal as fuel with super-critical technology (</u>*using Imported coal)

<u>Technology</u>: The super-critical technology is commercially available in turbine capacity of 500MW, 660MW, 800 MW and above[32]. Since no supercritical turbine of less than 500 MW is commercially available and 660 MW is the next commercially available size, 660 MW has been used for comparison of levelised tariff for power generation using coal as fuel with supercritical technology with that of the project activity. Fossil fuel-fired (coal) power plants use steam to provide the mechanical power to electrical generators. Steam at super critical pressure and temperature 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. Super critical coal based steam turbine power plants operate on a Rankine cycle. The steam is generated by a boiler at super-critical pressure and temperature, where pure water passes through a series of tubes to capture heat from the furnace and gets converted to super heated steam. The boiler will be once through type. 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 at super critical parameters then enters the steam turbine throttle, where it powers the turbine and connected generator to make electricity. After the steam expands through the HP turbine, it goes back to the boiler to get re-heated. The reheated steam then enters the LP turbine and 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

[31] Page 2 of 13 of Chapter 6 in CEA general performance review http://www.cea.nic.in/reports/yearly/general_review_rep/0304/chap-6.pdf

[32] http://www.cea.nic.in/reports/articles/thermal/committee_recommend_thermal.pdf

typically remains around 36 to 40[33]%. This has been considered as one of the plausible baseline alternatives. As per Tool to determine the remaining lifetime of equipment, Annex 15 of EB 50 meeting report, the default technical lifetime of boiler and steam turbine is 25 years. Hence the default technical lifetime of coal based power plant is 25 years.

3.3) *Power generation using lignite as fuel*

Technology: The power generation technology (sub-critical) using coal/lignite as fuel is commonly available in size of 200/210/250[34] MW units each. Thus for comparison with project activity a lignite based power plant of 400 MW. (2 units of 200 MW each) has been considered. Fuel combustion in Circulating Fluid Bed ("**CFB**") 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 the bed by recycle loop. The very high internal and external circulating rates of solids, characteristics of the CFB, 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 the actual carbon content is surprisingly 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 Electrostatic Precipitators ("**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 25 to 30[35]%. This has been considered as one of the

[33] http://www.cea.nic.in/reports/articles/thermal/committee_recommend_thermal.pdf

[34] http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf ; Page (10 of 72)

[35] http://www.cea.nic.in/reports/yearly/general_review_rep/0405/ch6.pdf

plausible baseline alternatives. As per Tool to determine the remaining lifetime of equipment, Annex 15 of EB 50 meeting report, the default technical lifetime of boiler and steam turbine is 25 years. Hence the default technical lifetime of lignite based power plant is 25 years.

3.4) *Power generation using naphtha as fuel*

Technology: The power generation technology using Naphtha as fuel is same as that of the project activity. Thus for comparison with project activity a naphtha based power plant of 370 MW has been considered 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, naphtha 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 (@25-35 %[36] 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 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 to around 50% [37] . This has been considered as one of the plausible baseline alternatives. As per Tool to determine the remaining lifetime of equipment, Annex 15 of EB 50 meeting report, the default technical lifetime of gas turbine is 200,000 hours ≈ 23 years, whereas of boiler is 25 years. Hence the default technical lifetime of gas based power plant is 23 years conservatively.

3.5) *Power generation using run of river 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 reservoir storage based hydro power plants cater to the peak load power requirements of the grid. Thus they are not considered as an alternative to the project activity as the project activity (i.e gas based power plant) is aimed to cater the base load requirement of the grid.

The power generation facility delivering same services as GSEGL plant would be thus run-of-river based hydel power stations.

[36] Chapter 22.2.4, Page 7, Book authored by Dennis Snow titled "Plant Engineers Reference book" ,http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpjrYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result

[37] Chapter 22.2.4, Page 7, Book authored by Dennis Snow titled "Plant Engineers Reference book" ,http://books.google.co.in/books?id=KJOoQm3fbEoC&pg=PT433&lpg=PT433&dq=efficiency+of+open+cycle+power+plant&source=web&ots=HRYT81RY0h&sig=yRBE5betwGqHsZ6RQVpjrYZoQWQ&hl=en&sa=X&oi=book_result&resnum=6&ct=result

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 as described in the table[38] 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 (MW)		Capacity Developed		Capacity under construction		Capacity Developed + under development		Capacity yet to developed	
	Total	Above 25 MW	MW	%	MW	%	MW	%	MW	%
Gujarat	619	590	550	93.22	0	0	550	93.22	40	6.78

In the last five years the following hydel energy based power plants have been added to the western grid[39]:

S.No.	Power Plant Name	State	Date of Addition	Capacity (MW)
1.	Madhikheda 2	Madhya Pradesh	9-Sep-06	50
2.	Bansagar (IV) 2	Madhya Pradesh	30-Aug-06	10
3.	Madhikheda 1	Madhya Pradesh	28-Aug-06	20
4.	Bansagar (IV) 1	Madhya Pradesh	20-Aug-06	10
5.	S.Sarovar RBPH 5	Gujarat	7-Mar-06	200
6.	S.Sarovar RBPH 4	Gujarat	13-Oct-05	200
7.	S.Sarovar RBPH 3	Gujarat	30-Aug-05	200
8.	S.Sarovar RBPH 2	Gujarat	30-Apr-05	200
9.	Indira Sagar 8	Madhya Pradesh	23-Mar-05	125
10.	S.Sarovar RBPH 1	Gujarat	1-Feb-05	200
11.	Indira Sagar 6	Madhya Pradesh	29-Dec-04	125
12.	S.Sarovar CHPH 5	Gujarat	15-Dec-04	50
13.	Indira Sagar 7	Madhya Pradesh	27-Oct-04	125
14.	S.Sarovar CHPH 1	Gujarat	4-Oct-04	50
15.	S.Sarovar CHPH 2	Gujarat	4-Sep-04	50
16.	S.Sarovar CHPH 3	Gujarat	1-Sep-04	50
17.	S.Sarovar CHPH 4	Gujarat	1-Sep-04	50
18.	Indira Sagar 5	Madhya Pradesh	23-Jul-04	125
19.	Indira Sagar 4	Madhya Pradesh	28-Mar-04	125
20.	Indira Sagar 3	Madhya Pradesh	27-Feb-04	125
21.	Indira Sagar 2	Madhya Pradesh	18-Jan-04	125
22.	Indira Sagar 1	Madhya Pradesh	1-Jan-04	125
23.	Khopoli 2	Maharashtra	25-Mar-03	24
24.	Bansagar (III) 3	Madhya Pradesh	2-Sep-02	20
25.	Bansagar (II) 2	Madhya Pradesh	1-Sep-02	15
26.	Tawa 1	Madhya Pradesh	31-Mar-02	6.75
27.	Tawa 2	Madhya Pradesh	31-Mar-02	6.75
28.	Bansagar (II) 1	Madhya Pradesh	18-Feb-02	15

[38] http://www.cea.nic.in/reports/hydro/he_potentialstatus.pdf

[39] http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm ; Version: 01.1

S.No.	Power Plant Name	State	Date of Addition	Capacity (MW)
29.	Khopoli 1	Maharashtra	13-Feb-02	24

This data indicates that of the 2451.5 MW of addition in hydro power generation capacity, 93% 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.

3.6) *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 Central Electricity Regulatory Commission (“**CERC**”) and the State Electricity Regulatory Commissions (“**SERC**”) and the tariff is unilaterally decided by Nuclear Power Corp. Ltd. The levelized tariff of generation from nuclear energy is, however, higher than that from coal by about 15%[40]. Further, this option is not available to an IPP and hence has been excluded as a baseline option.

3.7) *Power generation using wind energy*

Power generation from wind does not meet the base load requirement for the grid on a continuous firm basis as wind is seasonal in nature and the capacity utilization factor is very low.

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.

Alternative 4: Import of electricity from connected grids, including the possibility of new interconnections

The details of net and total imports into the western regional grid from the other grids (Northern, Eastern, Southern, North-Eastern, Nepal and Bhutan) [41] over 5 years at the time implementation of the project are presented in the table below:

Western regional grid	2000-01	2001-02	2002-03	2003-04	2004-05
Net imports (GWh)[42]	321	-174.1	797	962	285

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

[41] http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm , Version 01.

[42] Indicates the imports that Western grid made from other interconnected grids, net of any exports

Total imports (GWh)[43]	524.2	388.0	1,338.4	962.4	605.2

The variation in the value of net and total imports from the western grid presented above clearly establishes the intermittent nature of power availability and is not firm supply like the CCPP. The actual power supply position during the period April 2006 – November 2006[44] is as follows

Regional Grid	Northern Region	Western Region	Southern Region	Eastern Region	North – Eastern Region
Power Requirement (Million Units)	188,794	215,983	157,179	62,347	7,534
Power Availability (Million Units)	168,611	186,904	155,790	60,706	6,888
Surplus / Deficit (-)	-20,183	-29,079	-1,389	-1,641	-646

It remains implied from the statistics above that all the regional grids in the country are power deficit.

Import of electricity from the inter-regional grid is not a plausible option due to intermittent power availability and power deficit nature of all the regional grids. Further, the import of power from grid is subjected to other transmission issues like availability of transmission corridor for long term etc. Hence this scenario is excluded from further consideration to determine the baseline alternative of the project activity.

<u>Plausible baseline scenarios:</u>

Analysing the alternatives available (*as discussed above in alternative 1 to 4*) to the project activity results in following plausible baseline scenario alternatives:

Scenario 1: Power generation using natural gas as fuel and combined cycle technology without CDM revenues (Project activity)

Scenario 2: Power generation using coal as fuel with sub-critical technology

Scenario 3: Power generation using coal as fuel with super-critical technology (imported coal)

Scenario 4: Power generation using lignite as fuel

Scenario 5: Power generation using naphtha as fuel

In order to identify the economically most attractive baseline scenario alternative, investment analysis is carried out for each of the above 5 plausible alternatives. The detailed economic evaluation is presented as step-2 in the following section.

Step 2: Identify the economically most attractive baseline scenario alternative:

AM0029 version 03 requires:

"The economically most attractive baseline scenario alternative is identified using investment analysis. Calculate a suitable financial indicator for all alternatives remaining after Step 1. Include all relevant costs (including, for example, the investment cost, fuel costs and operation and maintenance costs), and revenues (including subsidies/fiscal incentives, ODA, etc. where applicable), and, as appropriate, non-market costs and benefits in the case of public investors."

[43] Indicates only imports that Western grid made from other interconnected grids

[44] http://www.cea.nic.in/archives/exec_summary/mar07.pdf

GSEGL has chosen levelized tariff i.e., levelized cost of generation as the financial indictor for identifying the economically most attractive baseline scenarios of the 5 plausible scenarios identified under step 1 above. Levelized tariff accounts for all relevant costs, revenues and benefits that are available to investors in power sector in the country.

Further, for all power generation projects in India, levelized cost of electricity generation is one way to perform comparisons among different technologies (alternatives) since it allows to quantify, the unitary cost of the electricity (the kWh) generated during the lifetime of all the alternatives being compared. The levelized cost of electricity being a mean value, allows the immediate comparison with the cost of other alternatives. It considers the total electrical energy that the power plant will produce in its lifetime and it is divided between the total cost generated by construction investment along with the interest rate and the cash flow during construction plus the operation and maintenance cost, etc (considering everything in present money worth). The consideration of all the affecting components in present money worth in calculation of levelized cost of generation provides a level ground for comparison and justifies its use as a suitable indicator. It is also important to note that for all power generation projects in India which are evaluated by Ministry of Power, Government of India, levelized cost of generation[45] is the evaluation criteria.

Levelized Tariff

The basic levelized cost methodology used for the proposed project activity is based on Annex 7 of "Proposed Costs of Generating Electricity" published by IEA. The levelized cost has two cost components, fixed cost and variable cost.

For the scenarios 1, 2, 3, 4 and 5, as identified earlier 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[46] as per the guidelines prescribed by Central Electricity Regulatory Commission (CERC)[47]: The assumptions common across all 5 scenarios are as below.

1. Return on equity - 14% (as per CERC 2004 tariff regulations)
2. Debt: Equity ratio - 70: 30 (as per CERC 2004 tariff regulations)
3. Normative Plant Load Factor – 80% (As per Detailed Project report (DPR) - appendix VI - 1, sr. no. 5.)
4. O&M escalation – 4 % (GERC terms & condition of tariff- notification no 12 of 2005)
5. Interest on working capital – 9% (based on DPR)
6. Term of Debt as -12 years (based on REC letter)
7. Corporate Income Tax rate (inclusive of surcharge) – 33.66% (Income tax rates for FY 05-06)
8. Annual Discount factor – 11.10% (As per CERC Notification dated 04/04/2007)

Minimum Alternate Tax ("**MAT**") rate for the first 10 years considering 80IA benefit at 11.33%. All references to the assumptions have been provided in the levelized tariff calculation excel sheets[48] and have also been annexed to this PDD as Annex 7.

[45] http://powermin.nic.in/whats_new/competitive_guidelines.htm

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

[47] Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations, 2001 available on http://cercind.gov.in

[48] Please refer levelised tariff computations for 1,2,3,4 and 5 attached as Appendix 1

The variable cost has been calculated based on the cost of the fuel. The escalation in fuel price has been taken as stipulated under CERC norms[49].

Assumptions used for levelised tariff calculations specific to various fuels are presented in the following table:

Parameter	***Scenario 1*** **NG (Project activity without CDM)**	***Scenario 2*** **Coal- Sub critical steam**	***Scenario 3*** **Coal- Super critical steam**	***Scenario 4*** **Lignite**	***Scenario 5*** **Naphtha**
Plant cost, INR Million/MW	30.32	40.0	47.47	40.60	30.40
Plant Size, MW	351.43	400 (2x200)	660	400 (2x200)	351.43
Total Project Cost, INR Million	10656	16000	31331	16246	10683
Aux. Consumption (%)	3	9	9	9.5	3
Interest on Debt/loan (%)	11	11	11	11	11
O & M expenses (INR Million/MW/Yr)	0.912	1.265	1.184	1.265	0.76
NCV of fuel (kCal / SCM for natural gas & kCal /kg for rest of the alternatives)	8421.7	4150	5206	2800	10500
GSHR (kCal/ KWh) (Year 2 onwards)	1850	2500	2167	2750	1850
Fuel Price (Rs. / SCM for natural gas & Rs. /kg for rest of the alternatives)	7.57	1.89	0.979	0.80	17.40
Fuel price Escalation (%)	10.00	5.25	5.25	8.00	10
Depreciation Rate (%)	3.91	3.60	3.60	3.60	3.91

The detailed levelized tariff calculations for each of these 5 scenarios have been presented in Appendix-1. The Summary of Levelized tariff for all plausible baseline scenarios is as follows:

S N	Plausible Baseline Scenario	Levelized Tariff (INR / KWh)
1.	Power generation using natural gas as fuel and combined cycle technology without CDM revenues	4.7749
2.	Power generation using coal as fuel (sub critical technology)	3.0960

[49] As per GERC tariff order 861/2006 dated 6th May 2006.

3.	Power generation using coal as fuel with super-critical technology (using Imported coal)	2.6921
4.	Power generation using lignite as fuel	3.0010
5.	Power generation using naphtha as fuel	7.4464

From the above table it can be seen that the option of coal based power plant with super-critical technology has the lowest levelized tariff of **2.6921 INR/KWh** and hence has been considered as the most plausible baseline scenario. It can also be seen that Levelized tariff for alternative-1 i.e. the project activity (NG) implemented without considering the CDM revenue, is among the costlier power generation alternatives.

Sensitivity Analysis:

Price of fuel, escalation rate for the fuel price, Station Heat Rate, Plant Load Factor and EPC cost are important factors which affect the unit cost of generation of electricity. Therefore, 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 5% and 10%;
2. Escalation rate for the fuel price: increase and decrease by 5% and 10%;
3. Station Heat Rate ("**SHR**"): increase and decrease by 5% and 10%;
4. Plant Load Factor ("**PLF**"): increase and decrease by 5% and 10%; and
5. Project cost: 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 Price Variation					
Fuel	**Base case**	**+10%**	**+5%**	**-5%**	**-10%**
Natural Gas (w/o CDM)	4.7749	5.1718	4.9733	4.5764	4.3779
Coal	3.0960	3.2905	3.1933	2.9987	2.9014
Coal Super-critical	2.6921	2.8282	2.7602	2.6240	2.5559
Lignite	3.0010	3.1744	3.0877	2.9143	2.8275
Naphtha	7.4464	8.1158	7.7811	7.1118	6.7771
Fuel Price Escalation Variation					
Fuel	**Base case**	**+10%**	**+5%**	**-5%**	**-10%**
Natural Gas (w/o CDM)	4.7749	5.1813	4.9717	4.5899	4.4161
Coal	3.0960	3.1888	3.1416	3.0518	3.0091
Coal Super-critical	2.6921	2.7573	2.7241	2.6611	2.6311
Lignite	3.0010	3.1437	3.0704	2.9352	2.8727
Naphtha	7.4464	8.0361	7.7334	7.1745	6.9167
SHR (Station Heat Rate) Variation					
Fuel	**Base case**	**+10%**	**+5%**	**-5%**	**-10%**
Natural Gas (w/o CDM)	4.7749	5.1718	4.9733	4.5764	4.3779
Coal	3.0960	3.2777	3.1869	3.0051	2.9142
Coal Super-critical	2.6921	2.8198	2.7559	2.6282	2.5644
Lignite	3.0010	3.1763	3.0887	2.9133	2.8256
Naphtha	7.4464	8.1158	7.7811	7.1118	6.7771
PLF (Plant Load Factor) Variation					
Fuel	**Base case**	**+10%**	**+5%**	**-5%**	**-10%**
Natural Gas (w/o CDM)	4.7749	4.7017	4.7365	4.8173	4.8644
Coal	3.0960	2.9957	3.0435	3.1540	3.2185
Coal Super-critical	2.6921	2.5754	2.6310	2.7596	2.8347
Lignite	3.0010	2.8922	2.9440	3.0640	3.1339
Naphtha	7.4464	7.3780	7.4106	7.4861	7.5301
Project Cost Variation					
Fuel	**Base case**	**+10%**	**+5%**	**-5%**	**-10%**
Natural Gas (w/o CDM)	4.7749	4.8373	4.8061	4.7436	4.7124
Coal	3.0960	3.2467	3.1902	3.0345	2.9915
Coal Super-critical	2.6921	2.7994	2.7457	2.6385	2.5848
Lignite	3.0010	3.0933	3.0471	2.9549	2.9087
Naphtha	7.4464	7.5062	7.4874	7.4239	7.4015

From the data presented above, it can be observed that with variations in price of fuel, escalation rate for the fuel price, SHR, PLF and Project cost, power generation using natural gas as fuel continues to remain more expensive than power generation using lignite and coal (both sub critical and Super critical technology) 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. The project activity did not receive any subsidies or fiscal incentives.

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 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.

<u>Steps for Additionality Check</u>

The Project start date is prior to the date of validation of the PDD and to demonstrate that the incentive from the CDM was seriously considered in the decision to proceed with the project activity, the following document was shared with the DOE:

- Extract of the Minutes of 37th Meeting of Board of Directors of Gujarat State Energy Generation Limited held on 25th September 2007 at Board Room of GSPC Limited, 2nd Floor, GSPC Bhavan, Gandhinagar - 382011

The start date of the project is based on the date of contract with Engineering; Procurement & Construction contractor on 29th December 2007.

The "seriousness" of prior consideration of incentives from CDM is evident from the documents referred above. The discussions held during the board meeting clearly specify that the project is feasible by claiming CDM benefits.

The project implementation timeline and CDM implementation timeline are provided in the table below to demonstrate the seriousness of CDM consideration:

Date	Implementation of Project Activity	Reference/ Remarks
12-Apr-07	Environmental clearance from Ministry of Environment & Forests (MoEF)	Letter from MoEF, Dt. 12 Apr 2007
11-Jun-07	Consent to establish from Gujarat Pollution Control Board (GPCB)	GPCB Letter, Dt. 11 Jun 2007
25-Sep-07	Board resolution to avail CDM benefits in order to make 350 MW CCPP financially viable	Extract of the minutes of 37th meeting of Board of Directors of the company, Dt. 25 Sep 2007

Date	Implementation of Project Activity	Reference/ Remarks
5-Nov-07	Sanction of rupee term loan by Rural Electrification Corporation (REC)	Loan sanction letter from REC, Dt. 5 Nov 2007
12-Dec-07	Invitation for participation in CDM stakeholder consultation meeting	Letter from GSEGL to stakeholders, Dt. 12 Dec 2007
28-Dec-07	Stakeholders consultation for CDM project	Minutes of meeting, Dt. 28 Dec 2007
29-Dec-07	Signing of EPC Contract with BHEL	Copy of EPC Contract
23-Jan-08	Notice to proceed for EPC of the project	Letter to BHEL, Dt. 23 Jan 2008 Starting date of the project activity
25-Mar-08	Gas sales contract with Gujarat State Petroleum Corporation Limited (GSPCL)	Gas sales contract, Dt. 25 Mar 2008
8-May-08	Contract with CDM Consultant – I	Engagement letter between first CDM consultant and GSEGL
18-Jun-08	Power purchase agreement (PPA) with Gujarat Urja Vikas Nigam Limited (GUVNL)	PPA, Dt. 18 Jun 2008
04-May-09	Invitation of offers from DOE	Emails sent by GSEGL to various DOEs
09-Aug-10	Contract with CDM consultant - I terminated	Termination of first CDM consultant
18-Aug-10	Contract of GSEGL with another CDM consultant	Engagement letter, Dt. 18 Aug 2010 Appointment of second CDM consultant
18-Aug-11	Appointment of DOE	Work order to BVC
26-Sep-11	Meeting with DNA for HCA	Meeting Invitation from DNA
January 13	Expected Date of Commissioning	Plant Monthly Progress Report

The chronology of events indicates that the earliest date at which the implementation or construction or real action of the project activity was initiated is **29th December 2007** (Signing of EPC Contract), Hence the same has been considered as the project activity start date. This is in line with the project activity start date guideline as recommended in the Glossary of CDM terms, (version 05)[50].

[50] http://cdm.unfccc.int/Reference/Guidclarif/glos_CDM.pdf

Step 1: Benchmark investment analysis

Demonstrate that the proposed CDM project activity is unlikely to be financially attractive by applying sub-step 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 and assessment of additionality (Version 6, EB 65)" 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, version -03.

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

The paragraph 4 under sub-step (2b), option III of the additionality tool version -06 recommends the following guideline

"Identify the financial/economic indicator, such as IRR, most suitable for the project type and decision context."

Considering the context of decision making levelised cost for power generation (INR / kWh) has been regarded as the most suitable indicator for the project type. The detailed explanation to justify the appropriateness of the financial indicator is as follows

In this regard please refer to the paragraph-19 of the "Guidelines on the Assessment of Investment Analysis" version – 05.

"If the proposed baseline scenario leaves the project participant no other choice than to make an investment to supply the same (or substitute) products or services, a benchmark analysis is not appropriate and an investment comparison analysis shall be used. If the alternative to the project activity is the supply of electricity from a grid this is not to be considered an investment and a benchmark approach is considered appropriate."

Choice of financial indicator:

The present project activity is a green field natural gas based grid connected Combined Cycle Power Plant (CCPP) of 351.43 MW capacity. GSEGL is a Special Purpose Vehicle (SPV) formed by GSPC (Gujarat State Petroleum Corporation) to generate power in Gujarat. It is apparent that the project participant is involved only in power generation activity and in absence of the project activity the project proponent would have invested in developing power plant based on any of the alternatives mentioned in section B.4. above.

Hence in line with the stipulations of AM0029, version -03 and also following the investment analysis guideline, version -05 the levelised cost of power generation has been considered as the suitable financial indicator.

To further substantiate the choice of the financial indicator as considered in the benchmark analysis please refer to the relevant section of the hand book on "India's Electricity Sector Widening Scope for Private Participation", 6th edition[51]. The guideline elaborates the gradual invention of levelised tariff to facilitate tariff based bidding process for the private sector power projects in India.

It is quite explicit from the above discussion that levelised tariff is the key indicator to evaluate the financial proposal of any private sector power producer.

[51] The relevant document has been submitted to the DOE during validation.

Similar approach (i.e. levelised cost of generation of different alternatives) has been followed by GSEGL in order to carry out financial evaluation of the candidate project activity while deciding upon the project investment.

Determination of the investment benchmark:

The lowest value of levelised cost of generation of all the baseline alternatives discussed in section B.4. of this document has been considered to determine the benchmark of the investment analysis. Explanation to justify the suitability of the benchmark is as follows.

For benchmark, the Sub-step 2b, option III of additionality tool , version 6 states "Discount rates and benchmarks shall be derived from:....

The approaches suggested to determine the benchmark in paragraph a to c under sub-step (2b), option III are appropriate when Internal Rate of Return (IRR) is identified as the financial indicator. Hence the same has not been considered appropriate to determine the benchmark.

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Paragraph d under sub-step (2b), option III of the additionality tool refers to a Government/official approved benchmark where such benchmarks are used for investment decisions. There is no such Government/official approved benchmark[52] available for private sector power generation in India.

Paragraph e under sub-step (2b), option III of the additionality tool (Version 6, EB 65) suggests the option of using any other indicators, if the project participants can demonstrate that the above Options are not applicable and their indicator is appropriately justified.

Given the above discussion, in the context of the project activity, the lowest levelised cost of power generation amongst all the plausible baseline options, has been considered as the suitable benchmark.

Benchmark analysis using project IRR as the financial indicator:

In addition to the above, project IRR has also been estimated for the project activity. In this regard please refer to paragraph 12 of the guidelines on the assessment of investment analysis, version -05 (EB62; Annex-05.2.1). The guideline recommends the following to determine the benchmark

"In cases where a benchmark approach is used the applied benchmark shall be appropriate to the type of IRR calculated. Local commercial lending rates or weighted average costs of capital (WACC) are appropriate benchmarks for a project IRR. Required/expected returns on equity are appropriate benchmarks for equity IRR."

In the present context in line with the financial indicator (project IRR) Weighted Average Cost of Capital (WACC) of the project activity has been considered as the investment benchmark. Further, the financial indicator i.e. project IRR will be computed post tax hence the same approach (post tax) will be followed while estimating the WACC i.e. investment benchmark of the project activity. In this regard it is worthwhile to note that that project activity can be implemented by any other entity apart from the project participant. Hence following the guideline provided in the sub-step 2b, option III of the tool version 6 the benchmark has been derived based upon the parameters that are standard in the market and not linked to the subjective profitability expectation or risk profile of the project developer.

WACC has been calculated as per the following illustration:

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[52] Central Electricity Authority (CEA) /or Central Electricity Regulatory Commission (CERC) do not specify any benchmark return in order to evaluate investment in power project in India

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

Cost of Equity:

Paragraph 15 of the investment analysis guideline, version -05 provides the following guideline to determine the cost of equity

"If the benchmark is based on parameters that are standard in the market, the cost of equity should be determined either by: (a) selecting the values provided in Appendix A; or by (b) calculating the cost of equity using best financial practices, based on data sources which can be clearly validated by the DOE, while properly justifying all underlying factors."

In case of the present project activity the cost of equity has been determined following the option (b) as mentioned in the guideline above. The Capital Asset Pricing Model (CAPM) has been followed considering Beta values of selected power generating companies in India that were listed at the time of investment decision making process. Detailed calculations of cost of equity and WACC along with an elaboration of the approach are provided in Appendix – 03 of this document. The cost of equity has been estimated at 20.07%.

Cost of Debt:

Actual interest rate as on loan disbursement date, which is 11%, as per the letter from Rural Electrification Corporation, has been considered as Cost of Debt.

Debt - Equity Ratio:

Paragraph 18 of the guideline on the assessment of investment analysis, version -05 provides the following in order to determine the debt/equity finance structure.

"If the benchmark is based on parameters that are standard in the market, then the typical debt/equity finance structure observed in the sector of the country should be used."

In this regard please refer to the Central Electricity Regulatory Commission (CERC) tariff order dated 26th March, 2004[53] that specifies that debt and equity to be considered at 70:30 for tariff determination. The same has been applied in the present context.

WACC:

Referring to the explanation above the WACC of the project activity has been estimated at 12.85%.

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

Comparison using as the financial indicator:

As demonstrated above, 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[54] calculations is presented in the table below:

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
1.	Project activity implemented as a project without	4.7749

[53] http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

[54] The detailed excel sheets of these calculations are enclosed as appendix 1A – 1E and also would be made to the DOE for verification.

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
	the CDM revenue	
2.	New power plant (s) based on coal (sub critical technology)	3.0960
3.	New power plant (s) based on coal with super-critical technology	2.6921
4.	New power plant (s) based on lignite	3.0010
5.	New power plant (s) based on naphtha	7.4464

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

The Cost of Power Generation using coal with supercritical technology has been considered as the benchmark, as this is the most economic and technologically viable project option to the project proponent. Comparison using project IRR as the financial indicator:

Project IRR has been considered as the financial indicator for the project activity. In this regard please refer to the discussion in section B.4 above on assumption considered to estimate levelised The same set of assumptions has been considered to determine the IRR of the project activity. In order to compute the IRR of the project activity the annual cost of generation as computed to determine the levelised tariff over 20 year period has been used.

The project IRR has been estimated at 11.63% which is lower than the applicable investment benchmark value of 12.85%.

Sub-step 2d (Sensitivity Analysis)

The findings of sensitivity analysis on levelized tariff of generation for natural gas, naphtha, 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, PLF and EPC cost, power generation using natural gas as fuel continues to remain more expensive than power generation using coal with both sub critical and super critical technologies or lignite as fuels.

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 and assessment of additionality, Version 6, EB 65)*" agreed by the CDM Executive Board.*

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

The common practice analysis has been carried out following the "Tool for the demonstration and assessment of additionality" (Version 06.0.0, EB65)[55].

Step 1: Calculate applicable output range as +/-50% of the design output or capacity of the proposed project activity.

The project activity is of capacity 351.43 MW; in accordance to step 1, "applicable output range" would be from 175.71 (project capacity-50%) to 527.15 (project capacity + 50%).

[55] http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-01-v6.0.0.pdf

Also, following the default choice as recommended in "Tool for the demonstration and assessment of additionality" (Version 06.0.0, EB65), the applicable geographical area has been considered as the entire host country i.e. India.

The start date of the project activity is 29th December 2007. A list of 280 projects, commenced operations before the start date of the project activity and within the applicable output range, taken from the CEA database (version7 dated January 2012), is provided in the Annex 9.

Step 2: In the applicable geographical area, identify all plants that deliver the same output or capacity, within the applicable output range calculated in Step 1, as the proposed project activity and have started commercial operation before the start date of the project. Note their number N_{all}. registered CDM project activities shall not be included in this step

It can be seen Vemagiri CCCP (UNFCCC Ref No: 4334) is a registered CDM projects. In line with the guidelines on common practice these power plants are excluded in order to determine the gas based CCPP units similar to the project activity. Hence within the given geographical area number of power plants within the applicable output range to the project activity (Nall) has been estimated at **279**.

Step 3: Within plants identified in Step 2, identify those that apply technologies different than the technology applied in the proposed project activity. Note their number N_{diff}.

<u>Different Technologies (Energy source / fuel)</u>

Among these 279 projects, 216 projects use coal as primary fuel, 10 projects use lignite as primary fuel, 9 projects use Naptha as primary fuel, 1 project use oil as primary fuel, 12 are Nuclear power plants, and 26 are Hydro Power Plants.

Further, among the 5 units which use gas as a primary fuel, four units namely Essar GT IMP Unit 1, Paguthan Unit 4, Peeddapuram CCGT Unit 1 and P.Nallur CCGT Unit 1 have capacity to fire multiple fuels (atleast one fuel other than natural gas). 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 fuel (natural gas) fired plants.

Hence these **278** projects are considered as applying technologies different from the candidate project activity.

$\mathbf{N_{diff} = 278}$

*Step 4: Calculate factor **F=1-Ndiff/Nall** representing the share of plants using technology similar to the technology used in the proposed project activity in all plants that deliver the same output or capacity as the proposed project activity.*

The discussion presented from step 1 to step 3 above have ascertained the value of N_{all} and N_{diff} as **279** and **278** respectively. Hence the calculation of factor F is as follows

Factor F = 1- (278/279)
= 0.0036

The proposed project activity is a .common practice. within a sector in the applicable geographical area if the factor F is greater than 0.2 and Nall-Ndiff is greater than 3.

$\mathbf{N_{all} - N_{diff} = 279-278 = 1}$
Factor F = 0.0036

The factor F is not greater than 0.2; also the difference between N_{all} and N_{diff} is not greater than 3.

Hence the above discussion demonstrates that the project activity is not a common practice within the given geographical area.

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 equation 6 of AM0029 version 03:

$$ER_y = BE_y - PE_y - LE_y \quad (1)$$

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 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 using equation 2 of AM0029 version 03:

$$BE_y = EG_{PJ,y} * EF_{BL,CO_2,y} \quad (2)$$

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 coal as fuel with super-critical technology 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 “Tool to calculate emission factor for an electricity system” (Version -2.0, EB - 50); and

Option 2: The combined margin, calculated according to “Tool to calculate emission factor for an electricity system” (Version -2.0, EB - 50), 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:

$$EF_{BL,CO_2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$ *(Refer equation 03 of AM0029 version 03)*

Where,

$COEF_{BL}$ = the fuel emission coefficient (tCO2e/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used

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

This determination will be made once at the validation stage based on an ex ante assessment, once again at the start of each subsequent crediting period (if applicable). If either option 1 (BM) or option 2 (CM) are selected, they will be estimated ex post, as described in “Tool to calculate emission factor for an electricity system” (Version -2.0, EB - 50).

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 “Tool to calculate emission factor for an electricity system” (Version -2.0, EB - 50).

Option 1: Build Margin, calculated according to “Tool to calculate emission factor for an electricity system (Version -2.0, EB - 50)***”***

The Build Margin emission factor $EF_{grid,BMy}$ (tCO_2/MWh) 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:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}} \qquad \textbf{(4)}$$

(using equation number 13 of Tool to calcúlate the emission factor for an electricty system, Version -2.0, EB - 50***)***

Where

$EF_{grid,,, BM, y}$ is Build Margin CO2 emission factor in year y (tCO2/MWh)

$EG_{m,y}$ is net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)

$EF_{EL,m,y}$ is CO2 emission factor of power unit *m* in year *y* (tCO2/MWh)

m is power units included in the build margin

y is most recent historical year for which power generation data is available

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 “Tool to calculate emission factor for an electricity system” (Version - 2.0, EB - 50). 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 Version 6 is 0.8123[56] tCO2e/MWh

[56] http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm

Option 2 The combined margin, calculated according to "Tool to calculate emission factor for an electricity system" (Version -2.0, EB - 50)***, using a 50/50 OM/BM weight.***

The calculation of the combined margin (CM) emission factor (EF_{grid},CM,$_y$) is based on Weighted Average CM method as per "Tool to calculate emission factor for an electricity system" (Version -2.0, EB - 50), is calculated as a combination of the Operating Margin (OM) and the Build Margin (BM). Considering the emission factors for these two margins as $EF_{grid,OM,y}$ and $EF_{grid,BM,y}$, then the $EF_{grid,CM,y}$ is given by:

$$EF_{grid,CM,y} = EF_{grid,OM,y} * w_{OM} + EF_{grid,BM,y} * w_{BM}$$

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 "Tool to calculate emission factor for an electricity system" (Version -2.0, EB - 50), 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 NEWNE electricity regional grid.

The Simple Operating Margin approach is appropriate to calculate the Operating Margin emission factor applicable in this case. As per "Tool to calculate emission factor for an electricity system (Version -2.0, EB - 50)" 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 profiles of Indian grids are as follows:

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
NEWNE	16.8%	18.0%	18.5%	19.0%	17.4%	15.9%
South	21.6%	27.0%	28.3%	27.1%	22.8%	20.6%
India	18.0%	20.1%	20.9%	21.0%	18.7%	17.1%

Source: CO_2 Baseline Database for the Indian Power Sector – Central Electricity Authority

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 and NEWNE grids 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 NEWNE region electricity grid for the latest three years available in the CEA database are given below:

Parameter	Value for Western Grid (tCO2e/MWh)
Operating Margin – 2007-08	0.9999
Operating Margin – 2008-09	1.0066
Operating Margin – 2009-10	0.9777
Average Operating Margin of last 3 years	0.9947

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 0.9947 tCO2e/MWh.

As mentioned earlier, the applicable Build Margin value is

	NEWNE Grid (tCO2e/MWh)
Build Margin (2009-10)	**0.8123**

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 0.9035** 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 as fuel with super-critical technology based power generation technology represents an economically attractive course of action, taking into account barriers to investment and therefore coal with super-critical technology based power generation technology has been identified as the baseline scenario.

The emission factor of coal as fuel with super-critical technology based power generation is calculated using the equation below:

$$EF_{BL,CO_2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \qquad (3)$$

$COEF_{BL}$ = Carbon Emission Factor of Coal with supercritical technology x Oxidation Factor of Lignite x 44/12

Based on IPCC 2006 value, $COEF_{BL}$ = 106.15 tCO_2/TJ = 0.10615 tCO_2/GJ

η_{BL} = 39.69%

$EF_{BL,CO2}(tCO2/MWh)$ = 0.09581 (tCO2e/GJ) x 3.6 (GJ/MWh)/ 39.69%

= 0.8690tCO2e/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	**0.8123**
Option 2: Combined Margin	**0.9035**
Option 3: Emission factor of coal based power plant	**0.8690**

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 **0.8123 tCO_2e/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 "Tool to calculate emission factor for an electricity system" (Version -2.0, EB - 50). As per this tool, 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 March 2011 and contains information up to 2009-10. 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 Build Margin number is not updated in the CEA database, it 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:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y}$$ (Using equation “1”of AM0029 - version 03)

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:

$$COEF_{f,y} = \sum NCV_y * EF_{CO_2,f,y} * OXID_f$$ **(**Using equation “1a”of AM0029 - version 03)

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: 8421.7 kCal/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 tCO_2e/tJ

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

$OXID_f$: Oxidation factor of Natural Gas as per IPCC Guidelines is 1

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

$COEF_{f,y}$ = (8421.7 x 4.1868)/10^9 (tJ/SCM) x 56.10 (tCO2e/tJ) x 1.0$COEF_{f,y}$ = 35259.97/10^9 (tJ/SCM) x 56.10 (tCO2e/tJ) x 1.0 x (10^6)

$COEF_{f,y}$ = 1978.08 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.

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:

$$LE_y = LE_{CH4,\,y} + LE_{LNG,\,CO2,\,y}$$ (Using equation "4" of AM0029 - version 03)

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:

$$LE_{CH4,\,y} = \lfloor FC_y . NCV_y . EF_{NG,\,upstream,\,CH4} - EG_{PJ,\,y} . EF_{BL,\,upstream,\,CH4} \rfloor . GWP_{CH4}$$ (Using equation "5" of AM0029 - version 03)

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[57]. 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 lignite	0.8 tCH4/kt	Guidelines for National Greenhouse Gas Inventories: Reference Manual,[58] the amount of CH4 generated during coal mining is primarily a function of coal rank and depth, gas content, and mining methods, as well as other factors such as moisture. Coal rank represents the differences in the stages of coal formation and depends on the pressure and temperature history of the coal seam; high coal ranks, such as bituminous coal, contain more CH4 than low coal ranks, such as lignite. Hence, 0.8 tCH4/kt lignite is used as a conservative value.
3	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.
4	Emission factor for fugitive CH4 upstream emissions for Natural Gas	296 tCH4/PJ	As per the Table 2 of the methodology, 296 tCH4/PJ is applicable for rest of the world.
5	Oxidation factor of natural gas	1	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.

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[57] 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)”. .

[58] http://www.ipcc-nggip.iges.or.jp/public/gl/guidelin/ch1ref7.pdf

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

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

1. Data / Parameter:	***$EF_{BM,y}$***
Data unit:	tCO_2e/MWh
Description:	Build Margin Emission Factor of Western Regional Electricity Grid
Source of data used:	"CO_2 Baseline Database for Indian Power Sector" Version 6.0 March 2011 published by the Central Electricity Authority, Ministry of Power, Government of India. The "CO_2 Baseline Database for Indian Power Sector" is available at www.cea.nic.in
Value applied:	0.8123
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 Tool to calculate emission factor for an electricity system (Version -2.0, EB - 50).
Any comment:	-

<table>
<tr><td>2. Data / Parameter:</td><td>$EF_{OM,y}$</td></tr>
<tr><td>Data unit:</td><td>tCO_2e/MWh</td></tr>
<tr><td>Description:</td><td>Operating Margin Emission Factor of Western Regional Electricity Grid</td></tr>
<tr><td>Source of data used:</td><td>"CO_2 Baseline Database for Indian Power Sector" Version 6.0 dated March 2011 published by the Central Electricity Authority, Ministry of Power, Government of India.
The "CO_2 Baseline Database for Indian Power Sector" is available at www.cea.nic.in</td></tr>
<tr><td>Value applied:</td><td><table>
<tr><td>Operating Margin - 2007-08</td><td>0.9999</td></tr>
<tr><td>Operating Margin - 2008-09</td><td>1.0066</td></tr>
<tr><td>Operating Margin - 2009-10</td><td>0.9777</td></tr>
<tr><td>Average Operating Margin of last 3 years</td><td>0.9947</td></tr>
</table></td></tr>
<tr><td>Justification of the choice of data or description of measurement methods and procedures actually applied :</td><td>Operating Margin Emission Factor has been calculated by the Central Electricity Authority using the simple OM approach in accordance with Tool to calculate emission factor for an electricity system (Version -2.0, EB - 50).</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

3. Data / Parameter:	**Carbon Emission Factor of Coal, Lignite, Naphtha**
Data unit:	tC/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 and lignite: IPCC default emission factors for stationary combustion in the energy industries. Carbon Emission Factor for Naphtha: Table 1.3, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 1, Volume 2, Energy
Value applied:	**Fuel** / **Carbon Emission Factor (tC/TJ)** Coal: 26.13 Lignite: 28.95 Naptha: 20.00
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:	Please refer Annex 3.

Fuel	Carbon Emission Factor (tC/TJ)
Coal	26.13
Lignite	28.95
Naptha	20.00

4. Data / Parameter:	**Oxidation Factor of Coal, Lignite, 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 1.4, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 1, Volume 2, Energy
Value applied:	see table below
Justification of the choice of data or description of measurement methods and procedures actually applied :	Only IPCC default values are available.
Any comment:	-

Fuel	Oxidation Factor
Coal	1
Lignite	1
Naptha	1

5. Data / Parameter:	***η_{BL}* – Efficiency of coal fired power generating stations with supercritical technology**
Data unit:	-
Description:	Energy efficiency of coal based power plant with super critical technology which has been identified as the baseline scenario
Source of data used:	The efficiency value has been referred from British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 10 of 151. This value is corresponding to international coal under Indian condition for low super critical technology.
Value applied:	39.69%

Justification of the choice of data or description of measurement methods and procedures actually applied :	An overview (page no 9) on super critical technology in India by National Thermal Power Corporation (NTPC) is also mentions that the efficiency of the supercritical technology lies in the range of 37.6 % to 39.9% [59].
Any comment:	This is the efficiency value for coal based power generation with super critical technology

6. Data / Parameter:	**Lignite consumption in Lignite fired Power plants in the NEWNE region**
Data unit:	Million tonnes (MT)
Description:	This data is used as an input for calculating the Energy efficiency of Lignite fired power plants and used for further assessing efficiency of lignite power station
Source of data used:	CEA CO_2 baseline database, version -06
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. All data is from CEA CO_2 Baseline database, version – 06.
Any comment:	-

Lignite fired stations	**Lignite consumption Million Tonnes**
GIRAL (1)	399.6
GIRAL (2)	443.7
KUTCH LIG.	112.2
AKRIMOTA LIG	657.3
AKRIMOTA LIG	656.9
JALLIPPA KAPURDI TPP	199.1

7. 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 CH_4 emissions occurring in the absence of the project activity
Source of data used:	GCV of coal, Natural Gas and Naphtha are sourced from CEA database Version 06.
Value applied:	

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59 http://www.egcfe.ewg.apec.org/publications/proceedings/CleanerCoal/HaLong_2008/Day%202%20Session%203A%20-%20Pankaj%20Gupta%20Supercritical%20Technology%20in%20.pdf

<table>
<tr><td></td><td>

Fuel	GCV	NCV[60]	Unit
Coal	3755	3620	Kcal/Kg
Natural Gas	8800	8483	Kcal/SCM
Naphtha	11300	10122	Kcal/SCM

</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.</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

<table>
<tr><td>8. Data / Parameter:</td><td>Electricity Generation from Lignite fired power plants in the NEWNE Region</td></tr>
<tr><td>Data unit:</td><td>GWh</td></tr>
<tr><td>Description:</td><td>This data is used as an input for calculating the Energy efficiency of Lignite fired power plants and used for further assessing efficiency of Lignite coal power station</td></tr>
<tr><td>Source of data used:</td><td>CEA CO_2 baseline database version 6.0 March 2011</td></tr>
<tr><td>Value applied:</td><td>

Lignite fired stations	2009-10 Net Generation (GWh)
GIRAL	250
GIRAL	295
KUTCH LIG.	81
AKRIMOTA LIG	597
AKRIMOTA LIG	597
JALLIPPA KAPURDI TPP	155

</td></tr>
<tr><td>Justification of the choice of data or description of measurement methods and procedures actually applied :</td><td>Central Electricity Authority, Government of India 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 CO_2 emission factors, version -06 for all the regional grids in India. This database also contains information on electricity generation from all major thermal power stations in the country.</td></tr>
<tr><td>Any comment:</td><td>-</td></tr>
</table>

9. Data / Parameter:	**Carbon-di-oxide 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

[60] GCV to NCV :NCV of Coal is 5% lower than GCV likewise NCV of Natural Gas and Naptha is 10% lower than GCV: Table 2.7, Chapter 2, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf

	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:	-

10. 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-1 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	1.0
Justification of the choice of data or description of measurement methods and procedures actually applied :	As there are no national data available, IPCC default value based on is considered
Any comment:	-

11. 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:	Normative value from Central Electricity Regulatory Commission[61]
Value applied:	1850
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	-

12. Data / Parameter:	**CO_2 emissions from Build Margin Power plants in the NEWNE region**
Data unit:	tCO_2e
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 CO_2 Baseline database
Value applied:	Please refer the emission reduction sheet for individual values
Justification of the	Central Electricity Authority is Government of India undertaking mandated to

[61] CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

choice of data or description of measurement methods and procedures actually applied :	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 CO_2 emission factors for all the regional grids in India. This database also contains information on CO_2 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:

$\mathbf{ER_y = BE_y – PE_y – LE_y}$

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

= (351.43MW x 80% [62](PLF) x 8,760 (hours))*0.97

= 2,388,937 MWh

$EF_{BL,CO2,y}$ = 0.8123 tCO_2e/MWh. (refer section B.6.1)

Baseline Emissions = 2,388,937 MWh x 0.8123 tCO_2e/MWh = **1,940,533 tCO_2e**

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

= 2,388,937 (MWh) x (1850/1.1) (KCal/MWh) *(10^3/10^6) / 8421.70 (MCal/1000SCM)

= 491.83 (Mcum)

$COEF_{f,y}$ = 1978.08 tCO2e/Mcum (refer section B.6.1)

Project Emissions = 491.83 (Mcum) x 1,978.08 (tCO_2e/Mcum) =**972,875 tCO_2e**

Leakage

Leakage: ***Ly =*** **81,714 CO_2e** (Please refer Annex – 6 for details of Leakage calculations)

[62] As per Detailed project report dated May 2006, which was prepared by TCE Consulting Engineers

Emission Reductions = 1,940,533 tCO_2e – 972,875 tCO_2e – 81,714tCO_2e
= 885,944 tCO_2e

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 (tonnes of CO_2e)	Estimation of baseline emissions (tonnes of CO_2e)	Estimation of leakage emissions (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
1	972,875	1,940,533	81,714	**885,944**
2	972,875	1,940,533	81,714	**885,944**
3	972,875	1,940,533	81,714	**885,944**
4	972,875	1,940,533	81,714	**885,944**
5	972,875	1,940,533	81,714	**885,944**
6	972,875	1,940,533	81,714	**885,944**
7	972,875	1,940,533	81,714	**885,944**
8	972,875	1,940,533	81,714	**885,944**
9	972,875	1,940,533	81,714	**885,944**
10	972,875	1,940,533	81,714	**885,944**
Total (tonnes of CO_2e)	**9,728,750**	**19,405,330**	**817,140**	**8,859,440**

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 Non Renewable and less GHG Intensive Fuels".**

Reference: Available on http://cdm.unfccc.int, Version 03, EB 39, 30th May, 2008

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:

1. 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:	Fuel supplier data
Value of data applied for the purpose of calculating expected emission reductions in section B.5	491.83Mcum
Description of measurement methods and procedures to be applied:	The total fuel consumption will be monitored by GSPL on daily basis and will be cross-verified by GSEGL fortnightly. Data will be stored in electronic and 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. Please refer Annex 4 for further information.
QA/QC procedures to be applied:	Natural gas supply metering to the project will be subject to maintenance and testing at least once in year to ensure accuracy. Please refer Annex 4 for more details of QA/QC procedures.
Any comment:	100% of data will be monitored.

2. Data / Parameter:	**$NCV_{f,y}$**
Data unit:	kCal/SCM
Description:	The net calorific value (energy content) per volume unit of natural gas in year 'y' as determined from GSPL data
Source of data to be used:	Fuel supplier data
Value of data applied for the purpose of calculating expected emission reductions in section B.5	8421.7[63]
Description of measurement methods and procedures to be applied:	The calorific value of natural gas consumed would be provided by gas supplier and recorded by GSEGL for verification
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned.
Any comment:	The data will be archived electronically

3. Data / Parameter:	**$EF_{co2,f,y}$**
Data unit:	tCO_2e/GJ
Description:	CO_2 Emission Factor of Natural Gas

[63] This value is as per the detailed project report. NCV of LNG is reported in DPR, same value considered here (for NG) as a conservative approach

Source of data to be used:	Table 1.4, Chapter 1 (Introduction), Volume 2 (Energy) 2006 IPCC Guidelines for National Greenhouse Gas Inventories[64].
Value of data applied for the purpose of calculating expected emission reductions in section B.6	**56.1** tCO_2e/TJ
Description of measurement methods and procedures to be applied:	Default values for CO_2 Factor of Natural Gas as per Table 1.4 Chapter 1 (Introduction), Volume 2 (Energy), 2006 IPCC Guidelines for National Greenhouse Gas Inventories 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.

4. 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	1.0
Description of measurement methods and procedures to be applied:	Default values as per Table 1.4 Revised 2006 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.

[64] http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_1_Ch1_Introduction.pdf

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.

5. 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:	ABT meters installed by SLDC/GETCO at the project site are used for monitoring the net electricity generation.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2,388,937 MWh (Based on a PLF of 80% and auxiliary power consumption of 3%)
Description of measurement methods and procedures to be applied:	This will be ascertained based upon the measured value of net electricity supplied to the grid by the project activity. The State Load Despatch Centre (SLDC) will measure the $EG_{PJ,y}$ and will issue a weekly electricity generation certificate. The meter readings will be archived both electronically and on paper. Archived data will be kept up to two years from the end of crediting period. Refer Annex 4 for more details.
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:	-

6. Data / Parameter:	$EF_{BM,y}$
Data unit:	tCO_2/MWh
Description:	Build Margin Emission factor for NEWNE 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 6.0 dated 01 March 2011 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	**0.8123**
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 be applied:	No additional QA/QC procedures are planned.
Any comment:	-

7. Data / Parameter:	$EF_{BL,upstream,CH4}$
Data unit:	tCO_2e/GWh

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 CO_2 baseline database or CEA data power plant in case the database is not updated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	**10.91** tCO_2e/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 (tCH_4 or tCO_2e/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. Refer Annex 7 for details.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

8. Data / Parameter:	$\boldsymbol{COEF_{f,y}}$
Data unit:	tCO_2e/m^3
Description:	CO_2 Emission coefficient for natural gas
Source of data to be used:	Calculated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	= 35,259.97/10^9 (tJ/SCM) x 56.10 (tCO_2e/tJ) x 1.0 = 1,978.08tCO2e/Million cum
Description of measurement methods and procedures to be applied:	$COEF_{f,y}$ is calculated for natural gas using natural gas consumption value (in energy terms, based on quantity and calorific value) and natural gas emission factor as follows: $COEF_{f,y} = \sum NCV_y * EF_{CO_2,f,y} * OXID_f$
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

9. Data / Parameter:	PEy
Data unit:	tCO_2
Description:	Project emission due to combustion of fuel
Source of data to be used:	Calculated
Value of data applied for the purpose of	972,875

calculating expected emission reductions in section B.6	
Description of measurement methods and procedures to be applied:	Project emission due to combustion of fuel is calculated using (i)Total volume of natural gas combusted in the project plant and (ii) CO2 Emission coefficient for natural gas as follows: $PE_y = \sum_f FC_{f,y} \times COEF_{f,y}$
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

10. Data / Parameter:	***LE_y***
Data unit:	tCO_2/Yr
Description:	Leakage emissions
Source of data to be used:	Calculated
Value of data applied for the purpose of calculating expected emission reductions in section B.6	**81,714 tCO_2e**
Description of measurement methods and procedures to be applied:	(Refer section B.6.1 and **Annex – 6** for detailed calculations)
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

B.7.2 Description of the monitoring plan:

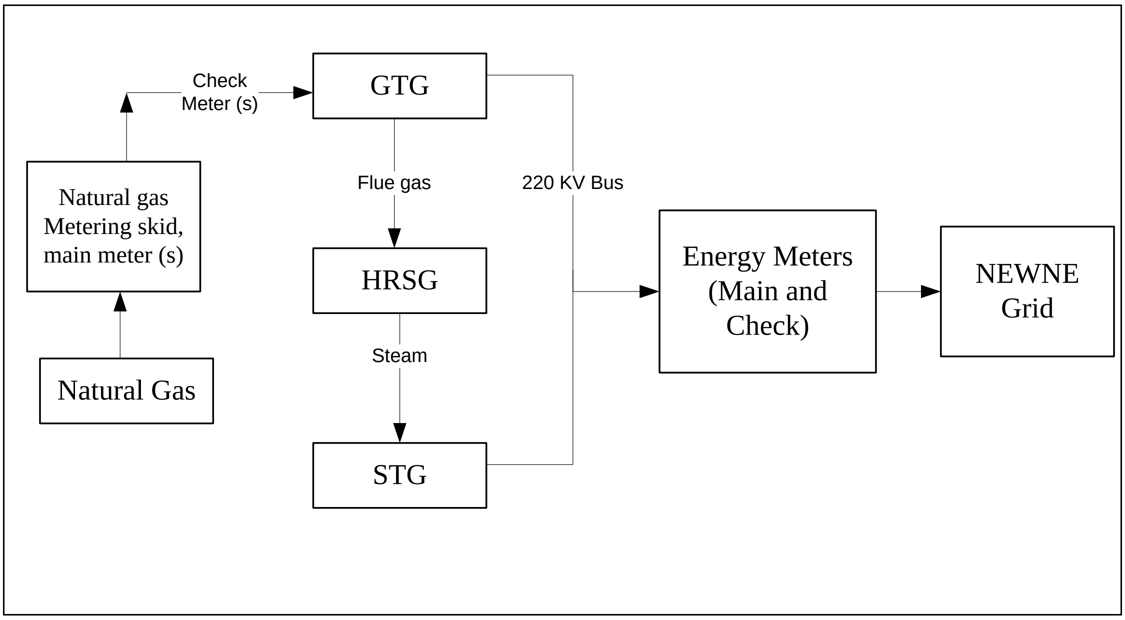
>> The Monitoring and Verification (M&V) procedures define a project-specific standard against which the project's performance (i.e. GHG reductions) and conformance with all relevant criteria will be monitored and verified. It includes developing suitable data collection methods and data interpretation 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.
5. Preparing for the requirements of an independent, third party auditor.

Electricity Metering: The delivered Energy (kWh) at ex- bus is metered by electricity meters installed on 220 KV side of generator transformer by project proponent.

Metering Equipment for Natural Gas Consumption: Metering equipments for natural gas consumption consists of differential pressure type meters along with differential pressure transmitters, pressure transmitters and Temperature transmitters. The Natural Gas Consumption metering is done using a main meter (s) (GSPL[65]) and a check meter (s) (GSEGL). The main meter is located at the supplier gas conditioning/metering skid and a check meter near the inlet to the gas turbine

The metering locations of natural gas and energy are provided in the diagram below;



- Above metering diagram denotes one main and check meter for both Energy and Natural gas measurement. In case multiple meters are used, the values will be summed to calculate the total gas consumption and energy generation values.

Emergency procedure

- If the both the meters (main and check) are found faulty in a particular period, emission reduction for that period would not be calculated.

Further details on monitoring plan has been presented in **Annex 4** of this document.

Training and maintenance: Technical know-how and high skill levels are essential for people in charge of power plant operations. In order to ensure that the key technical personnel in charge of operations and maintenance of the project activity are well versed with the technology and its operations, GSEGL would conduct/arrange specialised training programs as and when required.

Action Plan for Monitoring of 2% CER Revenue Committed Towards Sustainable Development

[65] The monitoring plan provided for natural gas quantity and NCV are based on the existing fuel supply contract with GSPCL, GSEGL expects that in future, the natural gas for this project activity may be sourced from a different supplier (s) as well. In such cases, the monitoring of gas quantity and NCV would be based on the supplier's monitoring system.

GSEGL is committed to contributing a minimum of 2% of the CDM revenue realized from the sale of CERs towards sustainable development. The expected CER generation from the project is **885,944 tCO_2e/year**.

GSEGL will undertake an annual review of the actual CERs accrued and the price transacted. On the basis of the actual price and exchange rate, GSEGL will commit 2% of the net revenue received from sale of CERs for sustainable development activities in the local areas through an annual review process. GSEGL commits to assign an official to oversee the activities towards sustainable development and to ensure that the activities are undertaken and concluded in a timely manner each year.

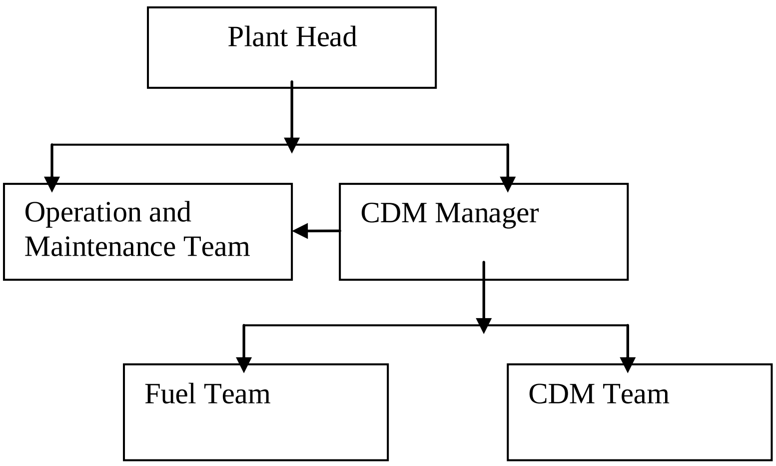
As part of the annual review, GSEGL will undertake informal discussions with the local community at the project site and commit the revenue towards society or community development activities in areas that are of most concern to the local population. These areas could include health, education, sanitation, skill development, infrastructure development, etc. The annual review process will detail the exact activities that would be undertaken using the 2% revenue and the detailed mode of implementation of the proposed activity.

Project Management Structure – Plant Level

At the power plant level the project management is basically engaged performing day to day activities related to operation and maintenance of the project. The team at the power plant level will primarily be collecting the CDM data and maintaining all records related to CDM activities of the project.

The organization structure and responsibility matrix for this CDM project activity is as below:

A) CDM Organization Structure:



The CDM Manager has been authorized to implement the PDD, sustainable development activities using 2% CER revenue and the Monitoring Plan and delegating all powers in relation thereto, to the CDM Manager including the power to direct O&M team, and fuel team, CDM team to:

a) Provide all information/data required for this monitoring plan.

b) Comply with all the requirements as per the Project Design Document and Monitoring Plan.

c) Adherence to the laid down protocols, procedures and processes, in relation to CDM project activity, by the aforesaid O&M team, fuel team and the CDM team

d) Refer all conflicts, discrepancies, mistakes, etc in relation to the Monitoring Plan of the CDM project activity, to the CDM manager for resolution, which resolution in this regard shall be final and binding on the aforesaid teams.

The O&M team is headed by the Head- O&M and the Fuel team is headed by the Fuel Manager.

S/No	Designation	Responsibilities
1	Plant Head	• Implement the organization structure. • Issue office orders, authorizing the CDM Manager to implement the PDD and the Monitoring plan and delegating to him all powers in relation thereto.
2	CDM Manger	• Direct the O& M team, fuel team, CDM team in relation to conformance with PDD and monitoring plan. • Storage of aggregated data. • Coordinate with DOE during verification process. • Monitor raw data in relation to Build Margin, Oxidation factor and where national institutions / AM 0029 default data are involved. • Randomly check data wherever necessary to independently check the authenticity of data and take corrective actions wherever required. • Resolve all conflicts in relation to CDM project activity. • Calculate ER and submit them to DOE. • Implement the PDD, sustainable development activities using 2% CER revenue and the Monitoring Plan. • Report non-conformances with PDD, Monitoring plan and CDM manager's directions
3	O & M team	• Calibrate and maintain data. • Monitor raw data
4	CDM Compiler	• Data processing • Data aggregation
5	Fuel Manager	• Monitor raw data

Further information on 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 27/06/2010

Gujarat State Energy Generation Limited has determined the application of baseline methodology for the identified CDM project. Gujarat State Energy Generation Limited is the project participant. The contact details appear in Annex 1 of this document.

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: 29/12/2007

The start date of a CDM project activity is "the earliest date at which either the implementation or construction or real action of a project activity begins". In light of the above definition, GSEGL has taken the start date as the date of contract with Engineering, Procurement & Construction (EPC) contractor, Bharat Heavy Electricals Limited (BHEL) . A copy of the EPC contract has been shared with DOE during the site visit.

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

>> 23 years and 0 months.

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

>> 10 year fixed crediting period

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 or **01/03/2013** whichever is later**.**

C.2.2.2. Length:

>> 10 years 0 months

SECTION D. Environmental impacts

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

>>

Environmental Component

The environmental impact assessment study for this project has been conducted as a part of a bigger project of capacity 1095MW. It incorporated assessment of baseline environment quality data during summer season of the year 2005 for identifying, predicting an devaluating the potential impacts due to the proposed gas based power plant unit and for evolving an effective EMP for minimizing the adverse impacts. Baseline data was collected for various environmental components, viz, air, noise,

water, land, biological and socio-economic within the impact zone of 10 km radial distance from the proposed power plant site.

The site for the proposed plant satisfies the requirements of site selection criteria as delineated by the Ministry of Environmental and Forests, Govt. of India. These are:

1. The site is more than 500 m away from the highway.
2. It is not located close to metropolitan cities, national park, wildlife sanctuary and ecologically sensitive areas.
3. The site is not located near any archaeological site of National importance.

Baseline Environmental Status and Assessment of Impacts :

a. Air Environment: The air quality was monitored on 24 hour basis during the summer season. It was found that the concentrations of SO_2 and NOx at all the sampling locations were observed to be well within the prescribed National Ambient Air Quality Standards for residential and rural area. Since cleaner fuel with no sulphur content will be used, prediction of impacts was carried out only for NOx and SO2 and was found that the impact of all the air pollutants from the plant would be insignificant.
b. Noise Environment : Vehicular traffic was found to be the major noise source and contributed mainly to background noise levels in the villages. The noise levels recorded in the individual process units exceeded the stipulated standards of CPCB because of the different machineries and equipment.
c. Water Environment : Samples for water quality assessment were collected from surface and groundwater sources in the surrounding villages. The values for demand parameters like DO, BOD and COD were observed under control mainly due to disposal of treated wastewater and considerable dilution available in Tapi river. About 80% of sewage and effluent discharge will be minimized after providing a reverse osmosis treatment to satisfy the requirements of Gujarat Pollution Control Board and most of the wastewaters after treatment would be reused within the power plant.
d. Land Environment : Analysis of samples of soil revealed the following ; the texture is clayey, pH is neutral to slightly alkaline which is conducive for plant growth having poor to moderate water holding capacity, moderately good in organic and nutrient content and is poor to medium fertile. There will be marginal sludge generation from the treatment plant which will be dewatered and sent to Gujarat Environ Protection and Infrastructure Limited.
e. Biological Environment: The topography is plain with numerous watersheds and waterlogged areas dominated by hydrophytes – mesophytes. The vegetation is subtropical coastal thorny scrub jungles with trees predominantly deciduous type. Trees are planted along the boundary of GSEGL plant resulting in 10 ha area of greenbelt.
f. Socio-Economic Environment : It is envisaged that with the commissioning of this power plant, there will be a positive impact on socio-economic environment with the implementation of welfare measures including provision of basic facilities/ amenities, which would result into increase in Quality of Life index (QoL).

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:

>>

GSEGL conducted a local stakeholder consultation meeting to discuss stakeholder concerns on the proposed Clean Development Mechanism (CDM) project – 351.43 MW natural gas based power plant at GSEG Ltd, Village Mora, Hazira, Surat.

Invitations to the stakeholders with project details, meeting schedule and agenda were issued on 12th December 2007. The stakeholders were also requested to raise their concerns and opinions either in person or by any other communication channels.

The meeting was held on 28th December 2007 at GSEGL site, Plot No. 148, opposite L&T gate no 3, Village Mora, Post Bhata, Surat Hazira Road, Surat.

The various stakeholder groups viz representatives from Ministry of Forest & Environment, Government of Gujarat, Gujarat Pollution Control Board, Gujarat Industrial Development Corporation (GIDC), Consultants/ Advisors, NGOs, participants from local communities, state government and governmental agencies, employees and contractors were identified and invited to attend the meeting. The invitations were sent through individual letters and notices in the village panchayat offices.

The objective of the meeting was introduced by Mr Ahmed of GSEG Limited. He further suggested the participants to elect a chairman to conduct the meeting. Mr. Kiran Upadhyay, Project Office, Government of Gujarat Forests and Environment Department to chair the meeting which was seconded by Mr. D.S Parmar, R.O., GIDC and Mr. B.D. Prasad, representative of GPCB. Accordingly, the meeting was further conducted by Mr. Upadhyay.

The agenda set in the notification was approved by the chairman and due consent of the participants was obtained. Subsequently, he invited the representative of first CDM consultant to provide a brief on the CDM project cycle and the role of local stakeholders. The representative briefed the participants about the Kyoto Protocol and mechanisms there-in. He elaborated on CDM and need for the project under this mechanism to catalyze sustainable development. He outlined that the local stakeholders concern are to be internalized in any project under clean development mechanism of the Kyoto Protocol.

Subsequently, he also provided a brief on the project, elucidating the likely environmental and social impacts of the project.

The Chairman encouraged the participants to seek clarifications on the project, its environmental and social impacts, CDM project cycle, UNFCCC, and Kyoto Mechanisms. Participants were also given further time to go through the project documents that are made available at the site of the meeting. It was also told that the documents will continue to be available for study. The chairman invited the participants to voice their concerns regarding environmental, social, economic, institutional, cultural impacts of the project and seek any clarifications.

E.2. Summary of the comments received:

>> Local stakeholders namely Mr.Jitendra Gandhi, Mr.Prasanta Sahoo, Mr.M.K.Gupta, Mr.Chetan Moravala and Mr.Dipak Patel raised their concerns, questions and comments about the project.

Answers/Clarifications were provided to all of them and the summary of local stakeholders' concerns, questions and comments along with provided answers/clarifications is presented in the table below:

Stakeholder concern / question / comment	**Answer / outcome**
Environment	
The process of CDM was requested to be elaborated	The question was addressed and process explained in local language.
Will there be any major noise pollution because of this project.	There will no major noise pollution because of the operation of this plant. Proper care will be taken to see that plant follows all the norms prescribed by the Gujarat Pollution Control Board.
Has the pollution control board prescribed the norms for effluent treatment?	The Pollution Control Board has prescribed certain norms for waste water treatment, which will be followed.
ECONOMIC	
Does this project lead to cost savings in energy generation as compared to other thermal power plant?	No, there will be no cost saving in terms of power generation. In fact the cost of power generation for this natural gas based plant will be more as compared to similar coal and lignite based power plant.
What is the technology to be employed?	Mr.Gajjjar of GSEG Ltd explained about the technology that will be used for power generation. He further informed that the power plant will be based on latest technology available and it will have 1 no. Gas Turbine and 1 no. Steam turbine with other necessary auxiliaries.
Will the plant face the problem of shortage in supply of natural gas in the future?	GSEGL has entered into MOU for long term Gas Supply with one of the supplier-producer of Natural Gas in Gujarat, and GSEGL has been assured for the supply of natural gas for the project. Also, the coast of Gujarat, where the project is being set up, is blessed with two LNG terminals (only terminals in India), which means that GSEGL if it requires can also procure gas from these LNG terminals. Further it was informed that by the time the power plant is commissioned there will be excess supply of gas due to commercial operations of gas fields identified in KG basin by various E&P companies.
SOCIAL	
Which countries are leaders in doing CDM projects?	As of now Brazil, India and China are the leaders in developing CDM projects.
Welfare and socio-economic development of the area through peripheral programs be initiated.	At the local level the Project activity has lead to creation of direct/indirect employment opportunity.

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

>>

The answers to queries from the local stake-holders during the meeting are provided in the above table. No adverse comments were received from any local stake-holders during this meeting.

The stakeholders viewed GSEG Limited as a reputed company contributing to local socio economy. Overall there was unanimous agreement that the proposed project was a beneficial project from sustainability view-point.

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:	Gujarat State Energy Generation Limited (GSEGL)
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Represented by:	
Title:	
Salutation:	Mr.
Last Name:	
Middle Name:	Sivadasan
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Annex 2

INFORMATION REGARDING PUBLIC FUNDING

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

Annex 3

BASELINE INFORMATION

Grid Emission Factors[66]:

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

	NEWNE Grid (tCO2e/MWh)
Operating Margin - 2007-08	0.9999
Operating Margin - 2008-09	1.0065
Operating Margin - 2009-10	0.9777
Average Operating Margin of last three years	0.9947

Build Margin

	NEWNE Grid (tCO2e/MWh)
Build Margin (2009-10)	0.8123

Combined Margin Calculations

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

	NEWNE Grid (tCO2e/MWh)
Combined Margin (2008-09)	0.9035

The emission factor of the baseline alternative (i.e. Coal based power plant with super critical technology) has been ascertained to understand the most conservative approach to calculate the baseline emission factor amongst all the options recommended in the AM0029 (version 03).

Efficiency of Coal based power plant with Super Critical technology (%)	**39.69%**	
Coal emission coefficient (IPCC)	**95.81**	tCO_2/TJ
	0.09581	tCO_2/GJ
Emission factor for baseline option	**0.8690**	tCO_2/MWh

[66] Baseline Carbon Dioxide Emissions from Power Sector, Baseline Carbon Dioxide Emission Database Version 5.0 dated November 2009 on http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm

The emission factor of lignite based power generation technology using 39.69% efficiency has been estimated at 0.869 (please see emission reduction sheet) tCO_2e/MWh.

It is evident that the value of build margin emission factor is the lowest of all the three options and hence it has been considered as the baseline emission factor for the project activity.

Annex 4

MONITORING INFORMATION

The general conditions set out for metering, recording, meter readings, meter inspections, Test & Checking and communication shall be applicable for both electrical energy and gas, where relevant and applicable.

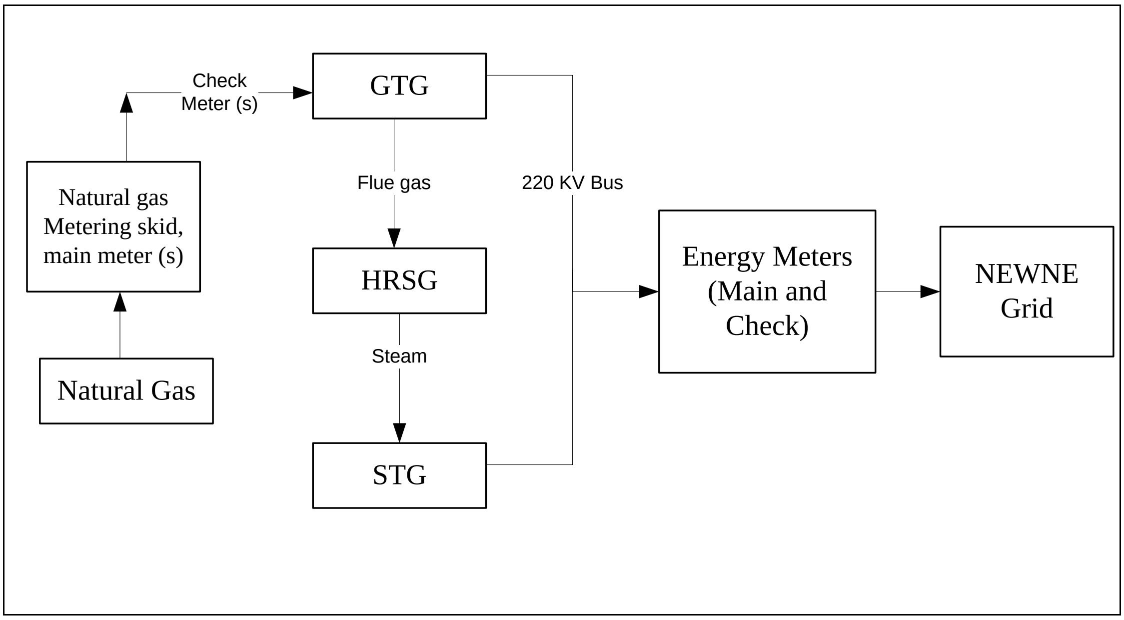
Electricity Metering: The delivered Energy (kWh) at ex- bus is metered by electricity meters installed on 220 KV side of generator transformer by project proponent.

Metering Equipment for electrical energy: The power generated by the project activity will be recorded using ABT meters connected to 220 kV line[67]. The ABT meters have been installed by SLDC and they will have complete control over the same. The meters (both main and check) provided are of static type with 0.2S class accuracy. The meters installed are capable of recording and storing half hourly readings of all the electrical parameters for a minimum period of 35 days with digital output.

The electricity meter reading report submitted by GETCO/SLDC and the invoices raised shall be the base audit document for verification protocol.

Calibration and periodical Testing of Electricity Meters: The meters will be calibrated at site at least once in five years as per Central Electricity Authority (Installation & Operation of Meters) Regulations 2006 which is available on public domain (http://www.cea.nic.in/e&c/regulations/notified_regulations/Metering_Regulations.pdf). Gujarat Energy Transmission Corporation Limited (GETCO) would be responsible for calibration of the energy meter. The testing will be carried out through NABL accredited mobile laboratory equipment or at any accredited test laboratory or by standard RSS meter available with GSEGL & recalibrated if required, at manufacturing works. The metering diagram for electricity for natural gas is provided below;

[67] If multiple feeders used for electricity export, the sum of electricity exported by all the feeders would be used for calculation.



- Above metering diagram denotes one main and check meter for both Energy and Natural gas measurement. In case multiple meters are used, the values will be summed to calculate the total gas consumption and energy generation values.

Natural gas metering: The natural gas metering shall be done using digital meters. The metering procedure would include recording readings from the meters. The meters shall be calibrated as per the manufacturer recommendations or at least once in a year, through by an accredited agency.

Metering Equipment for Natural Gas Consumption: Metering equipments for natural gas consumption consists of differential pressure type meters along with differential pressure transmitters, pressure transmitters and TT for temperature measurements. The Natural Gas Consumption metering is done using a main meter (s)[68] installed by gas supplier[69] and a check meter installed by GSEGL. The main meter is located at the supplier gas conditioning/metering skid and a check meter near the inlet to the gas turbine.

The main meter is installed and owned by the Gas Supplier.

Supplier Side Main Gas Flow Meter	Temperature Transmitter Accuracy Class	Pressure Transmitter Accuracy Class
Make: Daniel Type: Coriolis type Serial No.: 09-410168	1^0C	+/- 0.75% of span

[68] If a gas supplier installs more than one main meter, total reading would be calculated by summing individual meter readings.

[69] The monitoring plan provided for natural gas quantity and NCV are based on the existing fuel supply contract with GSPCL, GSEGL expects that in future, the natural gas for this project activity may be sourced from a different supplier (s) as well. In such cases, the monitoring of gas quantity and NCV would be based on the document (daily gas ticket) provided by supplier based on supplier supplier's monitoring system.

Check meters have been installed and owned by the Project proponent. It is **proposed** to install an ultrasonic flow meter to monitor the natural gas consumption at the supplier end as a check metering system with following specifications.

GSEGL Check Gas Flow Meter	Proposed Temperature Transmitter Accuracy Class	Proposed Pressure Transmitter Accuracy Class
Make: Daniel Type: Coriolis type	In the range of 0.15 to 0.50 ^{0}C (Proposed)	In the range of +/- 0.040 to 0.075 % of span (Proposed)

The measurement shall include all corrections in installations practices recommended for accurate metering of gas by the American Gas Association (AGA) as applicable and shall be binding to Gas supplier as well as project proponent.

Metering Equipment for Natural Gas Gross/Net Calorific Value: Gross/Net calorific value of the natural gas is measured by using an online chromatograph installed by Gas supplier at their end. The metering equipments shall be maintained in accordance with OEM guidelines as per relevant standards. The methodology adopted by GSPL for Gas analysis of Natural Gas is as per ISO 6976 and measured with a gas chromatograph system. GSPL will store the online reading in a Flow Computer. The same NCV value is reflected in the invoice raised by GSPL to the GSEGL.

GSPL issues a daily gas ticket to GSEGL clearly specifying the total volume of gas supplied and corresponding NCV. The volume of gas is recorded on daily basis by GSEGL. In addition to daily gas ticket gas invoice is also prepared by the gas supplier fortnightly and is sent to the project proponent. It clearly specifies the volume of gas supplied and corresponding NCV. The NCV of gas is recorded fortnightly.

The measurements are obtained daily by GSPL and are transmitted to Project Proponent every fifteen days. The data is recorded by the project proponent every fortnight.

The calibration of the on line chromatograph (main meter) shall be established by certified calibration gas. Heating value shall be computed as per ISO 6976. Calibration of the main and check meters for measuring NCV will be carried out by GSPL and GSEGL respectively as per the OEM guidelines and relevant standards.

In addition to the above, the following will be done:

- An internal audit team will be developed to review the performance of CDM related parameters of the project activity. The internal audit team will comprise of Executive Director (Gen) / Chief General Manager (HRA) , Nodal Officer, Chief Engineer (Plant Level), Executive Engineer (Efficiency). Chief Engineer (Plant) and the Executive Engineer (Plant) will be responsible for reviewing the plant performance data and will report to the nodal officer. The nodal officer and Executive Director (Gen) / Chief General Manager (HRA) will review the internal audit report and suggest the corrective measures if required.
- The quantitative details indicating the net exported electrical energy certified by internal audit team constituted for the purpose, for verification of the CERs. Further, the electricity meter reading submitted by GETCO/SLDC shall be the base audit document for verification protocol.
- The recording shall be as per accepted norms and additionally all the meters shall be calibrated as stated above.

The monitoring can be verified from number of sources which include:

- Power Purchase Agreement between GSEGL and GUVNL.
- Copies of bills/invoices raised (Electricity) and received (Natural gas)

The Power Purchase Agreement between GSEGL and GUVNL shall form the basis of the monitoring and verification protocol and shall be made available to internal audit team constituted for the purpose and/or the Designated Operating Entity.

Calculation of ratio of RLNG and NG in the gas supplied:

GSEGL will receive co-mingled gas (mixture of natural gas and regasified LNG[70]) from its gas supplier. The ratio of NG and RLNG in the received gas is calculated using the following procedure.

$$\%\text{ of NG in the gas received} = \frac{(NCV_{RLNG} - NCV_f)}{(NCV_{RLNG} - NCV_{NG})}$$

$$\%\text{ of RLNG in the gas received} = \frac{(NCV_f - NCV_{NG})}{(NCV_{RLNG} - NCV_{NG})}$$

% NG and RLNG will be calculated on a monthly basis using the above formulae while NCVf is the monthly arithmetic average value of NCV for the month calculated as described earlier in the monitoring plan.

[70] In this case RLNG and NG would be sourced from different gas sources and NCV of respective gas sources would used for emission calculation purpose.

Annex 5
Estimation of Weighted Average Cost of Capital

Weighted Average Cost of Capital:

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

Cost of Debt:
Actual interest rate as on loan disbursement date, which is 11%, as per the letter from Rural Electrification Corporation, has been considered as Cost of Debt.

Calculation of Cost of Equity:
The expected return on equity has been determined using the Capital Asset Pricing Model (CAPM)[71]. The CAPM economic model is used worldwide to determine the required/expected return on equity based on potential risk of an investment. The CAPM framework is the Nobel award winning work of financial economist Dr. William Sharpe.

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

Risk free rate:
The risk free rate is understood as the rate of return on an asset that is theoretically free of any risks, therefore the rate of interest on government bonds are considered as risk free rates. Page 191 of text book on "Corporate Finance Theory and Practice" by Dr. Aswath Damodaran[72] of Stern School of Business, New York University describes that the long term government bond rates are suitable indicators of risk free rates since the time horizon for this investment is long term.

Accordingly the risk free rate has been taken from long dated Indian government bond rates prior to the project investment decision. The data on government bond rates is published by Reserve Bank of India[73].

The applicable risk free rate is 7.89 %.

Risk Premium:

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

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

[73] (Web-link: http://rbidocs.rbi.org.in/rdocs/Publications/PDFs/80303.pdf)

The most common approach for estimating the risk premium is to base it on historical data, in the CAPM, the premium is estimated by looking at the difference between average return on stocks and applicable risk free rate as explained above. The average return on stocks has been determined by estimating the compounded annual return of the BSE – SENSEX.

The risk premium has been estimated at 11.48%.

Beta:

Beta (B) indicates the sensitivity of the company to market risk factors. For companies that are not publicly listed, the beta is determined by referring beta values of publicly listed companies that are engaged in similar types of business. Therefore, we have considered beta values of selected electricity generating companies in India. Beta values of individual companies have been sourced from Bloomberg and screenshots are available in appendix - 5. The table below summarises the beta values:

Company	Bloomber Symbol	Beta Values
BF Utilities LTd.	BFUT IN Equity	1.438
CESC Ltd.	CESC IN Equity	1.333
Neyveli Lignite Corpn.	NLC IN Equity	1.251
Tata Power Co. Ltd.	TPWR IN Equity	1.079
Gujarat Industries Power Co. Ltd.	GIP IS Equity	1.046
Reliance Infrastructure Ltd.	RELI IN Equity	0.973
Torrent Power	TPW IN Equity	0.309
Average		1.061

Debt - Equity Ratio:

Paragraph 18 of the guideline on the assessment of investment analysis, version -05 provides the following in order to determine the debt/equity finance structure.

"If the benchmark is based on parameters that are standard in the market, then the typical debt/equity finance structure observed in the sector of the country should be used."

In this regard please refer to the Central Electricity Regulatory Commission (CERC) tariff order dated 26th March, 2004[74] that specifies that debt and equity to be considered at 70:30 for tariff determination. The same has been applied in the present context.

Weighted Average Cost of Capital (WACC):

WACC has been estimated as per the following illustration
WACC = [D/ (D+E)]*[Cost of Debt] + [E/ (D+E)]*[Cost of Equity]

Therefore, WACC=20.07*30%+11.0*70%*(1-11.33%)=12.85%

[74] http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

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

Fugitive CH4 emission factor	tCH4/PJ	296.00	As per AM0029
Gas consumption	Mcum	491.83	
Calorific Value	kCal/SCM	8,421.70	
Conversion value kCal to TJ	*4.1858/10^9	0.0000	Note: values are very small and hence will look like 0
Converstion value SCM to Mcum	*1/10^6	0.0000	Note: values are very small and hence will look like 0
Calorific Value	TJ/Mcum	35.25	
TJ to PJ conversion	1/10^3	0.0010	
Energy content in Gas consumed	PJ	17.34	
Fugitive CH4 emissions	tCH4	5,131.95	
Global Warming Potential (GWP) of CH4		21.00	Normative - as per Kyoto protocol
Equivalent CO2 emissions	tCO2e	**107,771**	

Upstream fugitive emissions on account of leakage of NG by the project activity

$EF_{CO2,\ upstream,\ LNG}$	tCO_2/TJ	6.00	As per AM0029
Gas consumption (LNG 0%)	Mcum	-	
Gross Calorific value	Kcal/cum	9,345.63	As per DPR Appendix I Analysis of LNG
Calorific Value	kCal/SCM	8,421.70	As per DPR Appendix I Analysis of LNG
Conversion value kCal to TJ	*4.1858/10^9	0.0000	Note: values are very small and hence will look like 0
Converstion value SCM to Mcum	*1/10^6	0.0000	Note: values are very small and hence will look like 0
Calorific Value	TJ/Mcum	35.25	
Energy content in Gas consumed	TJ	-	
Leakage due to LNG	tCO2e	-	

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 $EF_{BL,upstream,CH4}$

= 2,388.937 GWh x 10.92 tCO2e (refer the next page for calculations of $EF_{BL,upstream,CH4}$)
= 26,081 tCO2e

Leakage = 107,771 tCO2e + 0 tCO2e – 26,057 tCO2e = 81,714 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	81,055,859	1,431	56,645		0.8		951,628
Lignite	2,880,180	1,150	2,504		0.8		42,072
Natural gas	1,737,006	1,860		30.96		296	192,464
Naphtha	2,920,292	3,296		39.82		4.1	3,429
Total							1,189,593

Net electricity generation (Million kWh) corresponding to build margin from CEA Database, Version 6	109,064

Fugitive emission factor (tCO2e/Million kWh)	**10.91**

Coal Based Power Plants (Build Margin – CEA Database Version 06)

S_NO	NAME	UNIT_NO	DT_ COMM	CAPACITY MW AS ON 31/03/2010	REGION	STATE	SECTOR	SYSTEM	TYPE	FUEL 1	FUEL 2	2009-10 Net Generation GWh	2009-10 Absolute Emissions t CO2	2009-10 Specific Emissions t CO2/MWh	2009-10 in Operating Margin	2009-10 in Build Margin
3	KAHALGAON	5	31-Mar-07	500	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	2,517	2,473,275	0.98		1
3	KAHALGAON	6	16-Mar-08	500	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	2,763	2,715,920	0.98		1
3	KAHALGAON	7	31-Jul-09	500	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	0	0	0.98		1
5	JOJBERA	4	23-Sep-05	120	CR	JHARKHAND	PVT	TATA PCL	THERMAL	COAL	OIL	795	899,097	1.13		1
6	CHANDRAPURA	7	4-Nov-09	250	CR	JHARKHAND	CENTER	DVC	THERMAL	COAL	OIL	0		0.00		1
6	CHANDRAPURA	8	31-Mar-09	250	CR	JHARKHAND	CENTER	DVC	THERMAL	COAL	OIL	0		0.00		1
10	MEJIA	5	31-Mar-07	250	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	715	770,045	1.08		1
10	MEJIA	6	1-Oct-07	250	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	1,260	1,353,558	1.07		1
13	TALCHER STPS	6	6-Feb-05	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	3,868	3,666,240	0.95		1
15	SANTALDIH	5	7-Nov-07	250	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL		1,192,345	0.00		1
17	BAKRESWAR	4	23-Dec-07	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	1,263	1,485,503	1.18		1
17	BAKRESWAR	5	7-Jun-09	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	1,137	1,402,859	1.23		1
18	D.P.L.	7	24-Nov-07	300	CR	WEST BENGAL	STATE	DPL	THERMAL	COAL	OIL	1,388	1,655,164	1.19		1
22	BUDGE BUDGE	3	29-Sep-10	250	CR	WEST BENGAL	PVT	CESC	THERMAL	COAL	OIL	150	158,812	1.06		1
48	SAGARDIGHI TPP	1	21-Dec-07	300	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	1,422	1,584,775	1.11		1
48	SAGARDIGHI TPP	2	20-Jul-08	300	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	1,499	1,639,036	1.09		1
83	GHTP (LEH.MOH.)	3	3-Jan-08	250	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	1,967	1,960,503	1.00		1
83	GHTP (LEH.MOH.)	4	31-Jul-08	250	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	376	379,258	1.01		1
85	KOTA	7	30-May-09	195	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	**373**	386,679	1.04		1
88	SURATGARH	6	29-Aug-09	250	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	0				1
94	PARICHA	3	29-Mar-06	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	1,283	1,589,674	1.24		1
94	PARICHA	4	28-Dec-06	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	1,191	1,481,759	1.24		1
97	RIHAND	3	31-Jan-05	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	3,876	3,702,449	0.96		1
97	RIHAND	4	24-Sep-05	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	3,573	3,413,199	0.96		1
98	UNCHAHAR	5	28-Sep-06	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	1,745	1,714,358	0.98		1
99	DADRI (NCTPP)	5	29-Jan-10	490	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	395	386,938	0.98		1
170	YAMUNANAGAR TPP	1	13-Nov-07	300	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	2,049	2,050,134	1.00		1
170	YAMUNANAGAR TPP	2	13-Nov-07	300	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	1,829	1,842,980	1.01		1
190	KORBA-V	7	30-Mar-07	250	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	1,747	1,764,579	1.01		1
190	KORBA-V	8	12-Dec-07	250	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	1,793	1,811,076	1.01		1
192	AMAR KANTAK EXT	5	15-Jun-08	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	1,053	1,207,513	1.15		1
193	SANJAY GANDHI	5	27-Aug-08	500	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	3,174	3,521,271	1.11		1
195	VINDH_CHAL STPS	9	27-Jul-06	500	CR	MADHYA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	4,214	4,037,026	0.96		1
195	VINDH_CHAL STPS	10	8-Mar-07	500	CR	MADHYA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	3,806	3,646,493	0.96		1
199	PARAS	2	31-Mar-08	250	CR	MAHARASHTRA	STATE	MAHAGENC(	THERMAL	COAL	OIL	1,318	1,651,383	1.25		1
199	PARAS	3	27-Mar-10	250	CR	MAHARASHTRA	STATE	MAHAGENC(	THERMAL	COAL	OIL	0	0	0.00		1
201	PARLI	6	16-Feb-07	250	CR	MAHARASHTRA	STATE	MAHAGENC(	THERMAL	COAL	OIL	1,274	1,573,900	1.24		1
201	PARLI	7	10-Feb-10	250	CR	MAHARASHTRA	STATE	MAHAGENC(	THERMAL	COAL	OIL	154	214,447	1.39		1
206	TROMBAY_Coal	8	30-Sep-09	250	CR	MAHARASHTRA	PVT	TATA PCL	THERMAL	COAL	OIL	1,426	1,416,239	0.99		1
254	SIPAT STPS	1	27-May-07	500	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	3,831	3,615,813	0.94		1
254	SIPAT STPS	2	27-Dec-08	500	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	3,886	3,667,494	0.94		1
256	RAIGARH TPP	1	8-Dec-07	250	CR	CHATTISGARH	PVT	JINDAL	THERMAL	COAL	OIL	1,827	1,735,048	0.95		1
256	RAIGARH TPP	2	6-Mar-08	250	CR	CHATTISGARH	PVT	JINDAL	THERMAL	COAL	OIL	1,886	1,811,491	0.96		1
256	RAIGARH TPP	3	10-Feb-07	250	CR	CHATTISGARH	PVT	JINDAL	THERMAL	COAL	OIL	1,877	1,783,614	0.95		1
256	RAIGARH TPP	4	17-Jun-08	250	CR	CHATTISGARH	PVT	JINDAL	THERMAL	COAL	OIL	1,895	1,824,826	0.96		1
257	BHILAI TPP	1	20-Apr-08	250	CR	CHATTISGARH	CENTER	NTPC/SAIL	THERMAL	COAL	OIL	1,413	1,478,450	1.05		1
257	BHILAI TPP	2	12-Jul-09	250	CR	CHATTISGARH	CENTER	NTPC/SAIL	THERMAL	COAL	OIL	795	831,681	1.05		1
261	RAJIV GANDHI TPS HISAR	1	31-Mar-10	600	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	0	**0**	**0.00**		**1**
262	CHHABRA TPS	1	30-Oct-09	250	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	203	388,003	**1.91**		**1**
264	ROSA TPP PH - 1	1	10-Feb-10	300	CR	UTTAR PRADESH	PVT	ROSA POWE	THERMAL	COAL	OIL	104	150,299	1.45		1
265	PATHADI TPS PH -I	1	4-Jun-09	300	CR	CHATTISGARH	PVT	LANCO AMA	THERMAL	COAL	OIL	1,423	1,595,829	1.12		1
265	PATHADI TPS PH -I	2	25-Mar-10	300	CR	CHATTISGARH	PVT	LANCO AMA	THERMAL	COAL	OIL	7	7,446	1.12		1
266	MUNDRA TPP PH-I	1	4-Aug-09	330	CR	GUJARAT	PVT	ADANI POW	THERMAL	COAL	OIL	1,459	1,417,380	0.97		1
266	MUNDRA TPP PH-I	2	17-Mar-10	330	CR	GUJARAT	PVT	ADANI POW	THERMAL	COAL	OIL	0		0.00		1

Gas Based Power Plants (Build Margin – CEA Database Version 06)

56	ROKHIA GT	8	31-Mar-06	21	CR	TRIPURA	STATE	TSECL	THERMAL	GAS	n/a	176	344,356	1.96		1
169	DHOLPUR	1	29-Mar-07	110	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	GAS		789	353,459	0.45		1
169	DHOLPUR	2	16-Jun-07	110	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	GAS		815	365,178	0.45		1
169	DHOLPUR	3	27-Dec-07	110	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	GAS		760	340,177	0.45		1
263	UTRAN CCCI	1	10-Jul-09	228	CR	GUJARAT	STATE	GSECL	THERMAL	GAS	n/a	577	203,879	0.35		1
263	UTRAN CCCI	2	10-Oct-09	146	CR	GUJARAT	STATE	GSECL	THERMAL	GAS	n/a	368	129,958	0.35		1
Total Gas													**1,737,006**			

Naptha Based Power Plants (Build Margin – CEA Database Version 06)

211	RATNAGIRI (	5	30-Apr-06	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	469	241,909	0.52		1
211	RATNAGIRI (	6	7-May-06	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	1,591	821,376	0.52		1
211	RATNAGIRI (	7	14-May-06	260	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	1,205	622,423	0.52		1
211	RATNAGIRI (	8	28-Oct-07	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	0	0	0.52		1
211	RATNAGIRI (	9	28-Oct-07	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	1,540	794,956	0.52		1
211	RATNAGIRI (	10	28-Oct-07	260	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	851	439,629	0.52		1
Total Naptha													2,920,292			

Lignite Based Power Plants (Build Margin – CEA Database Version 06)

164	GIRAL	1	28-Feb-07	125	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	LIGN	OIL	250	466,214	1.86		1
164	GIRAL	2	26-Dec-08	125	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	LIGN	OIL	295	517,600	1.76		1
179	KUTCH LIG.	4	1-Oct-10	75	CR	GUJARAT	STATE	GSECL	THERMAL	LIGN	OIL	81	130,941	1.62		1
251	AKRIMOTA L	1	31-Mar-05	125	CR	GUJARAT	STATE	GMDCL	THERMAL	LIGN	OIL	597	766,841	1.28		1
251	AKRIMOTA L	2	19-Dec-05	125	CR	GUJARAT	STATE	GMDCL	THERMAL	LIGN	OIL	597	766,285	1.28		1
267	JALLIPPA KA	1	16-Oct-09	135	CR	RAJASTHAN	PVT	RAJ WEST P	THERMAL	LIGN	OIL	155	232,299	1.50		1
Total Lignite													2,880,180			

Emission Factors

Type of FUEL	Net Calorific Value (TJ/ 10^3 tonnes or TJ/Mcum)	Carbon Emission Factor (t C/ TJ)	Fraction of Carbon Oxidised Oxidation Factor	Emission Coefficient (tCO2/ 103 tonnes or tCO2/Mcum)	Emission factor (tCO2/1000 t or tCO2/Mcum)
Coal	14.94	26.13	1.00	1,431	1,431
Lignite	10.83	28.95	1.00	1,150	1,150
Natural Gas	33.16	15.30	1.00	1,860	1,860
Naphtha	44.95	20.00	1.00	3,296	3,296

Note: For further details please refer ER calculation sheet

Sources

1. GCV of Coal, Natural Gas, Oil, Diesel: CO2 baseline data for the Indian Power Sector, CEA, version 6.0, Mar 2011
2. GCV of Lignite: Page no. 140, Table 6.3, Chapter 6; CEA General Review 2006:
3. Ratio of NCV:GCV for solid, liquid fuels = 0.95; Page no. 16, Chapter 1, Volume 2; 2006 IPCC Guidelines for National Greenhouse Gas Inventories
4. Ratio of NCV:GCV for gaseous fuels = 0.9; Page no. 16, Chapter 1, Volume 2; 2006 IPCC Guidelines for National Greenhouse Gas Inventories
5. Carbon Emission Factor for Coal and Lignite: http://unfccc.int/resource/docs/natc/indnc1.pdf, Page no. 37, Table 2.3, Chapter 2; India specific CO2 emission coefficients, India's first National Communication to the United Nations
6. Carbon Emission Factor for Natural Gas, Naptha, Oil and Diesel: Page no. 1.23, Table 1.4, Chapter 1, Volume 2; 2006 IPCC Guidelines for National Greenhouse Gas. http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_1_Ch1_Introduction.pdfInventories
7. Carbon Oxidation Factor: Page no. 1.23, Table 1.4, Chapter 1, Volume 2; 2006 IPCC Guidelines for National Greenhouse Gas Inventories

Annex 7
Assumptions for Calculation of Levelized Tariff

BASELINE ALTERNATIVE 1 : 351.43 MW NAPHTHA

Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	1,068.3	Calculated

Project Specifications			
Project capacity	MW	351.43	Project Capacity
Project life	Years	23	As same as the assumptions used for natural gas
Project cost per MW	Rs. Crores	3.04	Assumed to be same as the project cost - as per DPR Appendix IV, page 102
CoD - Combined cycle		Apr-10	As same as the assumptions used for natural gas

Project Financing			
Project Equity	%	30%	As same as the assumptions used for natural gas
Project Debt	%	70%	As same as the assumptions used for natural gas
Project Equity	Rs. Crores	320.5	Calculated
ROE	%	14%	As same as the assumptions used for natural gas
Project Debt	Rs. Crores	747.8	Calculated
Term of Debt	Years	12.0	As same as the assumptions used for natural gas
Interest on Debt	%	11.00%	As same as the assumptions used for natural gas
Moratium Peirod	Months	27.0	As same as the assumptions used for natural gas

Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2,685	As same as the assumptions used for natural gas
2nd year onwards	Kcal/Kwh	1,850	As same as the assumptions used for natural gas
Auxiliary Consumption			
1st year	%	1.00%	As same as the assumptions used for natural gas
2nd year onwards		3.00%	As same as the assumptions used for natural gas
PLF		80%	As same as the assumptions used for natural gas

Fuel Specifications			
Primary Fuel - Naphtha			
NCV of Naphtha	kCal/kg	10,500	CEA report of the expert committee on fuels for power generation ; page 5 of 17 http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Specific Naphtha consumption - 1st year	kg/kWh	0.26	Calculated
Specific Naphtha consumption - 2nd yr onwards	kg/kWh	0.18	Calculated
Landed Cost of Naphtha	Rs. / kg	17.40	CEA report of the expert committee on fuels for power generation, Page no.5, http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Annual Naphtha Price Escalation		10%	As same as the assumptions used for natural gas
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - 1 st year	ml / kWh	0.0	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - 2nd year onwards	ml / kWh	0.0	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	7,152	As per GERC tariff order 861/ 2006 ; Table 36, Page no 55 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en
Escalation for oil	%	10.50%	As same as the assumptions used for natural gas

Depreciation			
Recovery of Depreciation	%	90%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.91%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Discounting factor as Notified by CERC for bid evln	%	11.10%	http://www.cercind.gov.in/08022007/Notification_04-04-2007.pdf

O&M			
O&M Expenses	% of total capital	2.50%	http://www.thegef.org/gef/sites/thegef.org/files/repository/09.PAD.Annex_9.pdf, (page 5 of 13, provides O&M
Escalation Factor	%	4%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Tax			
Tax Rate	%	33.66%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act

Working Capital norms			
Receivables	Days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	30	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	15	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	9.00%	As same as the assumptions used for natural gas

BASELINE ALTERNATIVE 1 : 400 MW LIGNITE WITHOUT CDM

Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	1,624.6	Calculated

Project Specifications			
Project capacity	MW	400	Please refer to the CERC tariff order dated 26th March, 2004 (http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf). The order specifies the capacity of coal and lignite based power plant as 200 MW/210 MW/250 MW sets and 500 MW sets and above. In the present context 2 units of 200 MW each have been considered. This would be the closest to the capacity of the project activity.
Project life	Years	25	As per Annex 15, EB 50, http://cdm.unfccc.int/EB/050/eb50_repan15.pdf
Project cost per MW	Rs. Crores	4.06	http://mospi.nic.in/status_report_july_sept07.pdf, Page 15 of 237 mentions the cost for Expansion of NLC TPS - II is INR 2030.78 Crores. The capacity of NLC TPS-Ii can be seen in the link: http://www.nlcindia.com/index.php?file_name=about_01h
CoD		Apr-10	As same as the assumptions used for natural gas

Project Financing			
Project Equity	%	30%	As same as the assumptions used for natural gas
Project Debt	%	70%	As same as the assumptions used for natural gas
Project Equity	Rs. Crores	487.4	Calculated
ROE	%	14%	As same as the assumptions used for natural gas
Project Debt	Rs. Crores	1,137.2	Calculated
Term of Debt	Years	12.0	As same as the assumptions used for natural gas
Interest on Debt	%	11.00%	As same as the assumptions used for natural gas
Moratium Peirod	Months	27.0	As same as the assumptions used for natural gas

Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2,860	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf (using 1.1 mult factor)
2nd year onwards	Kcal/Kwh	2,750	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf (using 1.1 mult factor)
Auxiliary Consumption			
1st year	%	9.50%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
2nd year onwards		9.50%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
PLF		80%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Fuel Specifications			
Primary Fuel - Lignite			
NCV of Lignite	kCal/kg	2,800	CEA report of the expert committee on fuels for power generation ; page 4 of 17 http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Specific Lignite consumption - 1st year	kg/kWh	1.02	Calculated
Specific Lignite consumption - 2nd yr onwards	kg/kWh	0.98	Calculated
Landed Cost of Lignite	Rs. / kg	0.80	CEA report of the expert committee on fuels for power generation ; page 4 of 17 http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Annual Lignite Price Escalation		8.00%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - 1 st year	ml / kWh	5.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - 2 nd year onwards	ml / kWh	3.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	7,152	As per GERC tariff order 861/ 2006 ; Table 36, Page no 55 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en
Escalation for oil	%	10.50%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en

Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Discounting factor as Notified by CERC for bid evln	%	11.10%	http://www.cercind.gov.in/08022007/Notification_04-04-2007.pdf

O&M			
O&M expenses	Rs. Lakhs/MW	12.65	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation Factor	%	4%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Tax			
Tax Rate	%	33.66%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act

Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	9.00%	As same as the assumptions used for natural gas

BASELINE ALTERNATIVE 1 : 351.43 MW COMBINED CYCLE CCGT WITHOUT CDM

Project Cost			
Plant EPC	Rs. Crores	999.02	As per Detailed Project Report (DPR) Appendix IV
Other cost	Rs. Crores	35.97	As per Detailed Project Report (DPR) Appendix IV
Margin Money - Working Capital	Rs. Crores	-	As per Detailed Project Report (DPR) Appendix IV
Interest During Construction	Rs. Crores	26.99	As per Detailed Project Report (DPR) Appendix IV
Financing Charges	Rs. Crores	3.62	As per Detailed Project Report (DPR) Appendix IV
Project cost including IDC	Rs. Crores	1,065.6	Calculated

Project Specifications			
Project capacity	MW	351.43	As per the offer from EPC Contractor
Project life	Years	23	As per Annex 15, EB 50, http://cdm.unfccc.int/EB/050/eb50_repan15.pdf
Project cost per MW	Rs. Crores	3.03	Calculated, and as per DPR page 102 Appendix IV
CoD - Combined cycle		Apr-10	27 months from notice to Proceed for EPC (23 Jan 2008, Considering this as Zero date)

Project Financing			
Project Equity	%	30%	As per Detailed Project Report (DPR) Appendix VI-1
Project Debt	%	70%	As per Detailed Project Report (DPR) Appendix VI-1
Project Equity	Rs. Crores	319.7	Calculated
ROE	%	14%	As per Detalied Project Report (DPR)- appendix VI - 1
Project Debt	Rs. Crores	745.92	Calculated
Term of Debt	Years	12.0	As per the letter from Rural Electrification Corporation, dated 11/12/2007
Interest on Debt	%	11.00%	As per the letter from Rural Electrification Corporation, dated 18/12/2008
Moratorium Peirod	Months	27.0	As per the letter from Rural Electrification Corporation, dated 11/12/2007

Operating Norms			
Heat Rate			
Open cycle	Kcal/Kwh	2,685	As per http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf, page 12
Combined Cycle	Kcal/Kwh	1,850	As per Detailed Project report (DPR) - appendix VI - 1, sr. no. 21
Auxiliary Consumption			
Open cycle	%	1.00%	As per http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf page 12
Combined Cycle		3.00%	As per Detailed Project report (DPR) - appendix VI - 1, sr. no. 11
PLF		80%	As per Detailed Project report (DPR) - appendix VI - 1, sr. no. 5

Fuel Specifications			
Primary Fuel - Natural Gas			
CV of Liquified Natural Gas	kCal/kg	11,725	As per Detailed Project Report (DPR) - appendix VI - 1, sr. no. 8
NCV of Liquified Natural Gas	kCal/SCM	8,421.7	As per Detailed Project Report (DPR) - appendix I - LNG analysis
Specific Gas consumption - Combined cycle	SCM/kWh	0.22	Calculated
Landed Cost of NG	Rs. /SCM	7.57	Calculated
Annual Gas Price Escalation		10.00%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang =en
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - Open cycle	ml / kWh	0.0	
Specific Oil consumption - Combined cycle	ml / kWh	0.0	
Cost of Oil	Rs. / kl	7,152	As per GERC tariff order 861/ 2006 ; Table 36, Page no 55 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang
Escalation for oil	%	10.50%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang

Depreciation			
Recovery of Depreciation	%	90%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.91%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Discounting factor as Notified by CERC for bid evln	%	11.10%	http://www.cercind.gov.in/08022007/Notification_04-04-2007.pdf

O&M			
O&M Expenses	% of total capital cost	3.0%	Calculated value
	lakhs per MW	9.12	As per Detailed Project Report (DPR) - 9.12 Lakhs per MW, Appendix Vi-1, sr. no. 18
Escalation Factor	%	4%	As per Detailed Project Report (DPR)- appendix VI-1, Sr.no. 35

Tax			
Tax Rate	%	33.66%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act

Working Capital norms			
Receivables	Days	60	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	15	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	9.00%	As per Detailed Project Report (DPR)

BASELINE ALTERNATIVE 1 :400 MW COAL WITHOUT CDM

Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	1,600.0	Calculated

Project Specifications			
Project capacity	MW	400	Please refer to the CERC tariff order dated 26th March, 2004 (http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf). The order specifies the capacity of coal based power plant as 200 MW/210 MW/250 MW sets and 500 MW sets and above. In the present context 2 units of 200 MW each have been considered. This would be the closest to the capacity of the project activity.
Project life	Years	25	As per Annex 15, EB 50, http://cdm.unfccc.int/EB/050/eb50_repan15.pdf
Project cost per MW	Rs. Crores	4.00	http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf (page 11 of 17)
Date of commissioning		Apr-10	As same as the assumptions used for natural gas

Project Financing			
Project Equity	%	30%	As same as the assumptions used for natural gas
Project Debt	%	70%	As same as the assumptions used for natural gas
Project Equity	Rs. Crores	480.0	Calculated
ROE	%	14%	As same as the assumptions used for natural gas
Project Debt	Rs. Crores	1,120.0	Calculated
Term of Debt	Years	12.0	As same as the assumptions used for natural gas
Interest on Debt	%	11.00%	As same as the assumptions used for natural gas
Moratium Peirod	Months	27.0	As same as the assumptions used for natural gas

Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2,600	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf (stabilization period, page 1
2nd year onwards	Kcal/Kwh	2,500	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf (page 10)
Auxiliary Consumption			
1st year	%	9.00%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf (page 12, value for 200 MW
2nd year onwards		9.00%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf (page 12, value for 200 MW
PLF		80%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Fuel Specifications			
Primary Fuel - Coal			
NCV of Coal	kCal/kg	4,150	CEA report of the expert committee on fuels for power generation ; page 4 of 17 http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Specific Coal consumption - 1st year	kg/kWh	0.63	calculated
Specific Coal consumption - 2nd yr onwards	kg/kWh	0.60	calculated
Landed Cost of Coal	Rs. / kg	1.8929	CEA report of the expert committee on fuels for power generation ; page 12 of 17, http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Annual Coal Price Escalation		5.25%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - 1 st year	ml / kWh	4.5	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - 2 nd year onwards	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	7,152	As per GERC tariff order 861/ 2006 ; Table 36, Page no 55 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en
Escalation for oil	%	10.50%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109,

Depreciation			
Recovery of Depreciation	%	90%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Discounting factor as Notified by CERC for bid evln	%	11.10%	http://www.cercind.gov.in/08022007/Notification_04-04-2007.pdf

O&M			
O&M Expenses	Rs. Lakhs/MW	12.65	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation Factor	%	4%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Tax			
Tax Rate	%	33.66%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act

Working Capital norms			
Receivables	Days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

BASELINE ALTERNATIVE 1 : 660 MW SUPERCRITICAL COAL

Project Cost			
Plant EPC	Rs. Crores		
Other cost	Rs. Crores		
Margin Money - Working Capital	Rs. Crores		
Interest During Construction	Rs. Crores		
Financing Charges	Rs. Crores		
Project cost including IDC	Rs. Crores	**3,133.1**	Calculated from project cost per MW

Project Specifications			
Project capacity	MW	660	http://www.cea.nic.in/reports/articles/thermal/committee_recommend_thermal.pdf
Project life	Years	25	As per Annex 15, EB 50
Project cost per MW	Rs. Crores	4.747	British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 12 of 151(USD 1227 per kW ; exchange rate USD @ 40.23 INR)
CoD - Open cycle		Apr-10	

Project Financing			
Project Equity	%	30%	As same as the assumptions used for natural gas
Project Debt	%	70%	As same as the assumptions used for natural gas
Project Equity	Rs. Crores	939.9	Calculated
ROE	%	14%	As same as the assumptions used for natural gas
Project Debt	Rs. Crores	2,193.2	Calculated
Term of Debt	Years	12.0	As same as the assumptions used for natural gas
Interest on Debt	%	11.00%	As same as the assumptions used for natural gas
Moratium Peirod	Months	27.0	As same as the assumptions used for natural gas

Operating Norms			
Heat Rate			
1st year	Kcal/Kwh	2,167	Calculated from efficiency of 39.69%. The efficiency value hass been referred from British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 10 of 151(Corresponding to international coal under Indian condition for low super critical technology)
2nd year onwards	Kcal/Kwh	2,167	Calculated from efficiency of 39.69%. The efficiency value hass been referred from British High Commission Report on UMPP Risk Analysis, April 2007 ; Page no 10 of 151(Corresponding to international coal under Indian condition for low super critical technology)
Auxiliary Consumption			
1st year	%	9.00%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
2nd year onwards		9.00%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
PLF		80%	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Fuel Specifications			
Primary Fuel - Coal			
			CEA report of the expert committee on fuels for power generation ; page 4 of 17 http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
NCV of Coal	kCal/kg	5,206	
Specific coal consumption - 1st year	kg/kWh	0.42	calculated
Specific coal consumption - 2nd yr onwards	kg/kWh	0.42	calculated
Landed Cost of Coal	Rs. / kg	1.925	As per CEA report - page iv, price of imported fuel is Rs. 1925/tonne; http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf
Annual Coal Price Escalation		5.25%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109, Link:http://www.gercin.org/index.php?option=com_tarifforder&Itemid=32&year=2006&lang=en
Secondary Fuel -Oil			
NCV of Oil	kCal / lt	9,595	CEA CO2 Emission Database version 2: http://www.cea.nic.in/reports/planning/cdm_co2/cdm_co2.htm
Specific Oil consumption - 1st year	ml / kWh	4.5	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Specific Oil consumption - 2nd year	ml / kWh	2.0	http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Cost of Oil	Rs. / kl	7,152	As per GERC tariff order 861/ 2006 ; Table 36, Page no 55 of 109,
Escalation for oil	%	10.5%	As per GERC tariff order 861/ 2006 ; Page no 52 of 109,

Depreciation			
Recovery of Depreciation	%	90%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Rate of Depreciation - Book Depreciation	%	3.60%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Advance Against Depreciation	of loan amount	10%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Discounting factor as Notified by CERC for bid evln	%	11.10%	http://www.cercind.gov.in/08022007/Notification_04-04-2007.pdf

O&M			
O&M Expenses	Rs. Lakhs/MW	9.79	Calculated based on the O&M expenses provided in British High Commission Report on UMPP Risk Analysis
Escalation Factor	%	4%	CERC: http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf

Tax			
Tax Rate	%	33.66%	Income Tax Act
MAT Rate	%	11.33%	Income Tax Act
80IA Exemption	Years	10.00	Income Tax Act

Working Capital norms			
Receivables	Days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Spares	% of Project Cost	1%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Escalation factor for spares	%	6%	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Primary Fuel Stock	Days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Secondary Fuel Stock	days	60	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
O&M Expenses	Days	30	**CERC:** http://www.cercind.gov.in/13042007/Terms_and_conditions_of_tariff.pdf
Interest on Working Capital	%	9.00%	As same as the assumptions used for natural gas

Annex- 8

Substantiation on the suitability of the total investment of the project activity

The sub-components of the total project cost as considered in the levelised tariff calculation is presented in the table below:

S.No	Parameter	Value (Million INR)
1	EPC Cost	9990.17
2	Other cost	359.70
3	Finance Charges	36.22
4	Interest During Construction	269.88
5	Margin money – Working capital	0
	Total Project Cost	10656.00
	The project cost per MW	30.44

Reference: Detailed project report carried by TCE Consulting Engineers.

Annex- 9

List of power generating units in the applicable range, geographical area

A list of power plants in India, taken from the CEA database (version7 dated January 2012), having output capacity between 175.71 MW to 527.15 MW, which are commissioned before the start date (29th December 2007) of candidate project activity is provided in below table.

S_NO (as per CEA data base)	NAME	UNIT_NO	DATE OF COMM	CAPACITY MW AS ON 31/03/2011	REGION	STATE	SECTOR	SYSTEM	TYPE	FUEL 1	FUEL 2	CDM
3	KAHALGAON	1	31-Mar-92	210	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	
3	KAHALGAON	2	17-Mar-94	210	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	
3	KAHALGAON	3	24-Mar-95	210	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	
3	KAHALGAON	4	18-Mar-96	210	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	
3	KAHALGAON	5	31-Mar-07	500	CR	BIHAR	CENTER	NTPC	THERMAL	COAL	OIL	
4	TENUGHAT	1	14-Apr-94	210	CR	JHARKHAND	STATE	TVNL	THERMAL	COAL	OIL	
4	TENUGHAT	2	10-Oct-96	210	CR	JHARKHAND	STATE	TVNL	THERMAL	COAL	OIL	
7	DURGAPUR	2	5-Dec-81	210	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	

8	BOKARO B	1	24-Mar-86	210	CR	JHARKHAND	CENTER	DVC	THERMAL	COAL	OIL	
8	BOKARO B	2	7-Nov-90	210	CR	JHARKHAND	CENTER	DVC	THERMAL	COAL	OIL	
8	BOKARO B	3	31-Mar-93	210	CR	JHARKHAND	CENTER	DVC	THERMAL	COAL	OIL	
10	MEJIA	1	21-Dec-95	210	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	
10	MEJIA	2	24-Mar-97	210	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	
10	MEJIA	3	25-Mar-98	210	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	
10	MEJIA	4	12-Oct-04	210	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	
10	MEJIA	5	31-Mar-07	250	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	
10	MEJIA	6	1-Oct-07	250	CR	WEST BENGAL	CENTER	DVC	THERMAL	COAL	OIL	
12	I.B.VALLEY	1	22-May-94	210	CR	ORISSA	STATE	OPGC	THERMAL	COAL	OIL	
12	I.B.VALLEY	2	22-Oct-95	210	CR	ORISSA	STATE	OPGC	THERMAL	COAL	OIL	
13	TALCHER STPS	1	19-Feb-95	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	

13	TALCHER STPS	2	27-Mar-96	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	
13	TALCHER STPS	3	4-Jan-03	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	
13	TALCHER STPS	4	25-Oct-03	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	
13	TALCHER STPS	5	13-May-04	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	
13	TALCHER STPS	6	6-Feb-05	500	CR	ORISSA	CENTER	NTPC	THERMAL	COAL	OIL	
14	BANDEL	5	8-Oct-82	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
15	SANTALDIH	5	7-Nov-07	250	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
16	KOLAGHAT	1	13-Aug-90	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
16	KOLAGHAT	2	16-Dec-85	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
16	KOLAGHAT	3	24-Jul-84	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
16	KOLAGHAT	4	28-Dec-93	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
16	KOLAGHAT	5	17-Mar-91	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	

16	KOLAGHAT	6	16-Jan-93	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
17	BAKRESWAR	1	18-Jul-99	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
17	BAKRESWAR	2	20-May-00	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
17	BAKRESWAR	3	21-Mar-01	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
17	BAKRESWAR	4	23-Dec-07	210	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
18	D.P.L.	7	24-Nov-07	300	CR	WEST BENGAL	STATE	DPL	THERMAL	COAL	OIL	
22	BUDGE BUDGE	1	16-Sep-97	250	CR	WEST BENGAL	PVT	CESC	THERMAL	COAL	OIL	
22	BUDGE BUDGE	2	6-Mar-99	250	CR	WEST BENGAL	PVT	CESC	THERMAL	COAL	OIL	
23	FARAKKA STPS	1	1-Jan-86	200	CR	WEST BENGAL	CENTER	NTPC	THERMAL	COAL	OIL	
23	FARAKKA STPS	2	24-Dec-86	200	CR	WEST BENGAL	CENTER	NTPC	THERMAL	COAL	OIL	
23	FARAKKA STPS	3	6-Aug-87	200	CR	WEST BENGAL	CENTER	NTPC	THERMAL	COAL	OIL	
23	FARAKKA STPS	4	25-Sep-92	500	CR	WEST BENGAL	CENTER	NTPC	THERMAL	COAL	OIL	

23	FARAKKA STPS	5	16-Feb-94	500	CR	WEST BENGAL	CENTER	NTPC	THERMAL	COAL	OIL	
48	SAGARDIGHI TPP	1	21-Dec-07	300	CR	WEST BENGAL	STATE	WBPDC	THERMAL	COAL	OIL	
49	PURULIA PSS	1	18-Jul-07	225	CR	WEST BENGAL	STATE	WBSEDCL	HYDRO			
49	PURULIA PSS	2	23-Nov-07	225	CR	WEST BENGAL	STATE	WBSEDCL	HYDRO			
49	PURULIA PSS	3	27-Aug-07	225	CR	WEST BENGAL	STATE	WBSEDCL	HYDRO			
49	PURULIA PSS	4	18-Jul-07	225	CR	WEST BENGAL	STATE	WBSEDCL	HYDRO			
74	BADARPUR	4	2-Dec-78	210	CR	DELHI	CENTER	NTPC	THERMAL	COAL	OIL	
74	BADARPUR	5	25-Dec-81	210	CR	DELHI	CENTER	NTPC	THERMAL	COAL	OIL	
80	PANIPAT	5	28-Mar-89	210	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	
80	PANIPAT	6	1-Apr-01	210	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	
80	PANIPAT	7	26-Sep-04	250	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	
80	PANIPAT	8	28-Jan-05	250	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	

83	GHTP (LEH.MOH.)	1	29-Dec-97	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
83	GHTP (LEH.MOH.)	2	16-Oct-98	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
84	ROPAR	1	26-Sep-84	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
84	ROPAR	2	29-Mar-85	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
84	ROPAR	3	31-Mar-88	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
84	ROPAR	4	29-Jan-89	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
84	ROPAR	5	29-Mar-92	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
84	ROPAR	6	30-Mar-93	210	CR	PUNJAB	STATE	PSEB	THERMAL	COAL	OIL	
85	KOTA	3	25-Sep-88	210	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	
85	KOTA	4	1-May-89	210	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	
85	KOTA	5	26-Mar-94	210	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	
85	KOTA	6	30-Jul-03	195	CR	RAJASTHAN	STATE	RRVUNL	THERMAL	COAL	OIL	

86	N.A.P.S	1	29-Jul-89	220	CR	UTTAR PRADESH	CENTE R	NPC	NUCLE AR	NUCLE AR		
86	N.A.P.S	2	5-Jan-92	220	CR	UTTAR PRADESH	CENTE R	NPC	NUCLE AR	NUCLE AR		
87	R.A.P.S.	2	1-Nov-80	200	CR	RAJASTHAN	CENTE R	NPC	NUCLE AR	NUCLE AR		
87	R.A.P.S.	3	1-Mar-00	220	CR	RAJASTHAN	CENTE R	NPC	NUCLE AR	NUCLE AR		
87	R.A.P.S.	4	17-Nov-00	220	CR	RAJASTHAN	CENTE R	NPC	NUCLE AR	NUCLE AR		
88	SURATGAR H	1	10-May-98	250	CR	RAJASTHAN	STATE	RRVUNL	THERM AL	COAL	OIL	
88	SURATGAR H	2	28-Mar-00	250	CR	RAJASTHAN	STATE	RRVUNL	THERM AL	COAL	OIL	
88	SURATGAR H	3	29-Oct-01	250	CR	RAJASTHAN	STATE	RRVUNL	THERM AL	COAL	OIL	
88	SURATGAR H	4	25-Mar-02	250	CR	RAJASTHAN	STATE	RRVUNL	THERM AL	COAL	OIL	
88	SURATGAR H	5	30-Jun-03	250	CR	RAJASTHAN	STATE	RRVUNL	THERM AL	COAL	OIL	
91	OBRA	9	26-Jan-80	200	CR	UTTAR PRADESH	STATE	UPRVUNL	THERM AL	COAL	OIL	
91	OBRA	10	14-Jan-79	200	CR	UTTAR PRADESH	STATE	UPRVUNL	THERM AL	COAL	OIL	

91	OBRA	11	31-Dec-77	200	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
91	OBRA	12	28-Mar-81	200	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
91	OBRA	13	21-Jul-82	200	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
94	PARICHA	3	29-Mar-06	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
94	PARICHA	4	28-Dec-06	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
95	ANPARA	1	1-Jan-87	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
95	ANPARA	2	8-Jan-87	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
95	ANPARA	3	1-Apr-89	210	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
95	ANPARA	4	3-Jan-94	500	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
95	ANPARA	5	1-Oct-94	500	CR	UTTAR PRADESH	STATE	UPRVUNL	THERMAL	COAL	OIL	
96	SINGRAULI STPS	1	13-Feb-82	200	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
96	SINGRAULI STPS	2	25-Nov-82	200	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	

96	SINGRAULI STPS	3	28-Mar-83	200	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
96	SINGRAULI STPS	4	2-Nov-83	200	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
96	SINGRAULI STPS	5	26-Feb-84	200	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
96	SINGRAULI STPS	6	23-Dec-86	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
96	SINGRAULI STPS	7	24-Nov-87	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
97	RIHAND	1	31-Mar-88	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
97	RIHAND	2	5-Jul-89	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
97	RIHAND	3	31-Jan-05	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
97	RIHAND	4	24-Sep-05	500	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
98	UNCHAHAR	1	21-Nov-88	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
98	UNCHAHAR	2	22-Mar-89	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
98	UNCHAHAR	3	27-Jan-99	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	

98	UNCHAHAR	4	22-Oct-99	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
98	UNCHAHAR	5	28-Sep-06	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
99	DADRI (NCTPP)	1	21-Dec-91	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
99	DADRI (NCTPP)	2	18-Dec-92	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
99	DADRI (NCTPP)	3	16-Jun-92	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
99	DADRI (NCTPP)	4	24-Mar-94	210	CR	UTTAR PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
112	CHAMERA	1	28-Apr-94	180	CR	HIMACHAL	CENTER	NHPC	HYDRO			
112	CHAMERA	2	25-Apr-94	180	CR	HIMACHAL	CENTER	NHPC	HYDRO			
112	CHAMERA	3	22-Apr-94	180	CR	HIMACHAL	CENTER	NHPC	HYDRO			
115	NATHPA JHAKRI	1	31-Mar-04	250	CR	HIMACHAL	CENTER	SJVNL	HYDRO			
115	NATHPA JHAKRI	2	9-Mar-04	250	CR	HIMACHAL	CENTER	SJVNL	HYDRO			
115	NATHPA JHAKRI	3	13-Feb-04	250	CR	HIMACHAL	CENTER	SJVNL	HYDRO			

115	NATHPA JHAKRI	4	22-Jan-04	250	CR	HIMACHAL	CENTER	SJVNL	HYDRO			
115	NATHPA JHAKRI	5	20-Sep-03	250	CR	HIMACHAL	CENTER	SJVNL	HYDRO			
115	NATHPA JHAKRI	6	23-Nov-03	250	CR	HIMACHAL	CENTER	SJVNL	HYDRO			
168	TEHRI ST -1	1	19-Mar-07	250	CR	UTTARAKHAND	CENTER	THDC	HYDRO			
168	TEHRI ST -1	2	30-Jan-07	250	CR	UTTARAKHAND	CENTER	THDC	HYDRO			
168	TEHRI ST -1	3	25-Oct-06	250	CR	UTTARAKHAND	CENTER	THDC	HYDRO			
168	TEHRI ST -1	4	17-Jul-06	250	CR	UTTARAKHAND	CENTER	THDC	HYDRO			
170	YAMUNANAGAR TPP	1	13-Nov-07	300	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	
170	YAMUNANAGAR TPP	2	13-Nov-07	300	CR	HARYANA	STATE	HPGCL	THERMAL	COAL	OIL	
172	UKAI_Coal	3	21-Jan-79	200	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
172	UKAI_Coal	4	28-Mar-79	200	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
172	UKAI_Coal	5	30-Jan-85	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	

173	GANDHI NAGAR	3	20-Mar-90	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
173	GANDHI NAGAR	4	20-Jul-91	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
173	GANDHI NAGAR	5	17-Mar-98	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	1	23-Mar-82	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	2	15-Jan-83	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	3	15-Mar-84	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	4	9-Mar-86	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	5	23-Sep-86	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	6	18-Nov-87	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
177	WANAKBORI	7	31-Dec-98	210	CR	GUJARAT	STATE	GSECL	THERMAL	COAL	OIL	
181	ESSAR GT IMP.	1	10-Aug-95	515	CR	GUJARAT	PVT	ESSAR	THERMAL	GAS	NAPT	
185	PAGUTHAN	4	11-Dec-98	250	CR	GUJARAT	PVT	GPEC	THERMAL	GAS	NAPT	

187	GANDHAR GT	4	30-Mar-95	224.49	CR	GUJARAT	CENTER	NTPC	THERMAL	GAS	n/a	
188	KAKRAPARA	1	24-Nov-92	220	CR	GUJARAT	CENTER	NPC	NUCLEAR	NUCLEAR		
188	KAKRAPARA	2	4-Mar-95	220	CR	GUJARAT	CENTER	NPC	NUCLEAR	NUCLEAR		
189	SATPURA	6	30-Mar-79	200	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
189	SATPURA	7	20-Sep-80	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
189	SATPURA	8	25-Jan-83	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
189	SATPURA	9	27-Feb-84	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
190	KORBA-V	7	30-Mar-07	250	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	
190	KORBA-V	8	12-Dec-07	250	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	
191	KORBA-WEST	1	21-Jun-83	210	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	
191	KORBA-WEST	2	30-Mar-84	210	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	
191	KORBA-WEST	3	26-Mar-85	210	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	

191	KORBA-WEST	4	13-Mar-86	210	CR	CHATTISGARH	STATE	CSEB	THERMAL	COAL	OIL	
193	SANJAY GANDHI	1	26-Mar-93	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
193	SANJAY GANDHI	2	27-Mar-94	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
193	SANJAY GANDHI	3	28-Feb-99	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
193	SANJAY GANDHI	4	23-Nov-99	210	CR	MADHYA PRADESH	STATE	MPGPCL	THERMAL	COAL	OIL	
194	KORBA STPS	1	1-Mar-83	200	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
194	KORBA STPS	2	31-Oct-83	200	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
194	KORBA STPS	3	17-Mar-84	200	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
194	KORBA STPS	4	31-May-87	500	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
194	KORBA STPS	5	25-Mar-88	500	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
194	KORBA STPS	6	23-Feb-89	500	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
195	VINDH_CHAL STPS	1	10-Oct-87	210	CR	MADHYA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	

195	VINDH_CH AL STPS	2	23-Jul-88	210	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	3	3-Feb-89	210	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	4	26-Dec-89	210	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	5	31-Mar-90	210	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	6	1-Feb-91	210	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	7	3-Mar-99	500	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	8	26-Feb-00	500	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	9	27-Jul-06	500	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
195	VINDH_CH AL STPS	10	8-Mar-07	500	CR	MADHYA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
196	NASIK	3	31-Mar-79	210	CR	MAHARASHTR A	STATE	MAHAGEN CO	THERM AL	COAL	OIL	
196	NASIK	4	10-Jul-80	210	CR	MAHARASHTR A	STATE	MAHAGEN CO	THERM AL	COAL	OIL	
196	NASIK	5	30-Jan-81	210	CR	MAHARASHTR A	STATE	MAHAGEN CO	THERM AL	COAL	OIL	

197	KORADI	5	31-Mar-78	200	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
197	KORADI	6	30-Mar-82	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
197	KORADI	7	13-Jan-83	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
198	K_KHEDA II	1	26-Mar-89	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
198	K_KHEDA II	2	8-Jan-90	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
198	K_KHEDA II	3	31-May-00	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
198	K_KHEDA II	4	7-Jan-01	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
200	BHUSAWAL	2	28-Mar-79	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
200	BHUSAWAL	3	4-May-82	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
201	PARLI	3	20-Sep-80	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
201	PARLI	4	26-Mar-85	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
201	PARLI	5	31-Dec-87	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	

201	PARLI	6	16-Feb-07	250	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	1	15-Aug-83	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	2	11-Jul-84	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	3	3-May-85	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	4	8-Mar-86	210	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	5	22-Mar-91	500	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	6	11-Mar-92	500	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
202	CHANDRAPUR_Coal	7	1-Oct-97	500	CR	MAHARASHTRA	STATE	MAHAGENCO	THERMAL	COAL	OIL	
205	TROMBAY	1	23-Mar-90	500	CR	MAHARASHTRA	PVT	TATA PCL	THERMAL	OIL	GAS	
206	TROMBAY_Coal	5	25-Jan-84	500	CR	MAHARASHTRA	PVT	TATA PCL	THERMAL	COAL	OIL	
208	DHANU	1	6-Jan-95	250	CR	MAHARASHTRA	PVT	REL	THERMAL	COAL	OIL	
208	DHANU	2	29-Mar-95	250	CR	MAHARASHTRA	PVT	REL	THERMAL	COAL	OIL	

211	RATNAGIRI GAS	1	11-Dec-98	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	2	11-Dec-98	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	3	11-Dec-98	225	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	5	30-Apr-06	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	6	7-May-06	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	7	14-May-06	260	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	8	28-Oct-07	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	9	28-Oct-07	240	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
211	RATNAGIRI GAS	10	28-Oct-07	260	CR	MAHARASHTRA	PVT	RATNAGIRI	THERMAL	NAPT	GAS	
216	S.SAROVAR RBPH	1	1-Feb-05	200	CR	GUJARAT	STATE	SSVNL	HYDRO			
216	S.SAROVAR RBPH	2	30-Apr-05	200	CR	GUJARAT	STATE	SSVNL	HYDRO			
216	S.SAROVAR RBPH	3	30-Aug-05	200	CR	GUJARAT	STATE	SSVNL	HYDRO			

216	S.SAROVAR RBPH	4	13-Oct-05	200	CR	GUJARAT	STATE	SSVNL	HYDRO			
216	S.SAROVAR RBPH	5	7-Mar-06	200	CR	GUJARAT	STATE	SSVNL	HYDRO			
228	KOYNA-IV	15	28-Mar-00	250	CR	MAHARASHTRA	STATE	MAHAGENCO	HYDRO			
228	KOYNA-IV	16	3-Mar-00	250	CR	MAHARASHTRA	STATE	MAHAGENCO	HYDRO			
228	KOYNA-IV	17	25-Nov-99	250	CR	MAHARASHTRA	STATE	MAHAGENCO	HYDRO			
228	KOYNA-IV	18	7-Oct-99	250	CR	MAHARASHTRA	STATE	MAHAGENCO	HYDRO			
254	SIPAT STPS	1	27-May-07	500	CR	CHATTISGARH	CENTER	NTPC	THERMAL	COAL	OIL	
256	RAIGARH TPP	1	8-Dec-07	250	CR	CHATTISGARH	PVT	JINDAL	THERMAL	COAL	OIL	
256	RAIGARH TPP	3	10-Feb-07	250	CR	CHATTISGARH	PVT	JINDAL	THERMAL	COAL	OIL	
2	K_GUDEM NEW	1	27-Mar-97	250	SR	ANDHRA PRADESH	STATE	APGENCO	THERMAL	COAL	OIL	
2	K_GUDEM NEW	2	28-Feb-98	250	SR	ANDHRA PRADESH	STATE	APGENCO	THERMAL	COAL	OIL	
3	VIJAYWADA	1	1-Nov-79	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERMAL	COAL	OIL	

3	VIJAYWAD A	2	10-Oct-80	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
3	VIJAYWAD A	3	5-Oct-89	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
3	VIJAYWAD A	4	23-Aug-90	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
3	VIJAYWAD A	5	31-Mar-94	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
3	VIJAYWAD A	6	24-Feb-95	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
5	RAYAL SEEMA	1	27-Apr-94	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
5	RAYAL SEEMA	2	25-Feb-95	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
5	RAYAL SEEMA	3	25-Jan-07	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
5	RAYAL SEEMA	4	20-Nov-07	210	SR	ANDHRA PRADESH	STATE	APGENCO	THERM AL	COAL	OIL	
7	R_GUNDEM STPS	1	26-Nov-83	200	SR	ANDHRA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
7	R_GUNDEM STPS	2	29-May-84	200	SR	ANDHRA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	
7	R_GUNDEM STPS	3	13-Dec-84	200	SR	ANDHRA PRADESH	CENTE R	NTPC	THERM AL	COAL	OIL	

7	R_GUNDEM STPS	4	26-Jun-88	500	SR	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
7	R_GUNDEM STPS	5	26-Mar-89	500	SR	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
7	R_GUNDEM STPS	6	16-Oct-89	500	SR	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
7	R_GUNDEM STPS	7	26-Sep-04	500	SR	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
8	SIMHADRI	1	22-Feb-02	500	SR	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
8	SIMHADRI	2	24-Aug-02	500	SR	ANDHRA PRADESH	CENTER	NTPC	THERMAL	COAL	OIL	
13	PEDDAPURAM CCGT	1	8-Nov-02	220	SR	ANDHRA PRADESH	PVT	REL	THERMAL	GAS	NAPT	
14	RAICHUR	1	29-Mar-85	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	
14	RAICHUR	2	2-Mar-86	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	
14	RAICHUR	3	30-Mar-91	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	
14	RAICHUR	4	29-Sep-94	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	
14	RAICHUR	5	31-Jan-99	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	

14	RAICHUR	6	22-Jul-99	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	
14	RAICHUR	7	11-Dec-02	210	SR	KARNATAKA	STATE	KPCL	THERMAL	COAL	OIL	
16	KAIGA	1	26-Sep-00	220	SR	KARNATAKA	CENTER	NPC	NUCLEAR	NUCLEAR		
16	KAIGA	2	2-Dec-99	220	SR	KARNATAKA	CENTER	NPC	NUCLEAR	NUCLEAR		
16	KAIGA	3	11-Apr-07	220	SR	KARNATAKA	CENTER	NPC	NUCLEAR	NUCLEAR		
27	TUTICORIN	1	9-Jul-79	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
27	TUTICORIN	2	17-Dec-80	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
27	TUTICORIN	3	16-Apr-82	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
27	TUTICORIN	4	11-Feb-92	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
27	TUTICORIN	5	31-Mar-91	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
28	METTUR	1	4-Jan-87	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
28	METTUR	2	1-Dec-87	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	

28	METTUR	3	22-Mar-89	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
28	METTUR	4	16-Feb-90	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
29	NORTH CHENNAI	1	25-Oct-94	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
29	NORTH CHENNAI	2	27-Mar-95	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
29	NORTH CHENNAI	3	24-Feb-96	210	SR	TAMIL NADU	STATE	TNEB	THERMAL	COAL	OIL	
35	P.NALLUR CCGT	1	22-Feb-01	330.5	SR	TAMIL NADU	PVT	PPNPG	THERMAL	GAS	NAPT	
40	NEYVELI ST II	1	17-Jan-88	210	SR	TAMIL NADU	CENTER	NLC	THERMAL	LIGN	OIL	
40	NEYVELI ST II	2	6-Feb-87	210	SR	TAMIL NADU	CENTER	NLC	THERMAL	LIGN	OIL	
40	NEYVELI ST II	3	29-Mar-86	210	SR	TAMIL NADU	CENTER	NLC	THERMAL	LIGN	OIL	
40	NEYVELI ST II	4	30-Mar-91	210	SR	TAMIL NADU	CENTER	NLC	THERMAL	LIGN	OIL	
40	NEYVELI ST II	5	30-Dec-91	210	SR	TAMIL NADU	CENTER	NLC	THERMAL	LIGN	OIL	
40	NEYVELI ST II	6	30-Oct-92	210	SR	TAMIL NADU	CENTER	NLC	THERMAL	LIGN	OIL	

40	NEYVELI ST II	7	19-Jun-93	210	SR	TAMIL NADU	CENTE R	NLC	THERM AL	LIGN	OIL	
41	NEYVELI FST EXT	1	21-Oct-02	210	SR	TAMIL NADU	CENTE R	NLC	THERM AL	LIGN	OIL	
41	NEYVELI FST EXT	2	22-Jul-03	210	SR	TAMIL NADU	CENTE R	NLC	THERM AL	LIGN	OIL	
42	NEYVELI TPS(Z)	1	11-Oct-02	250	SR	TAMIL NADU	PVT	STCMS	THERM AL	LIGN	OIL	
43	M.A.P.P.	1	23-Jul-83	220	SR	TAMIL NADU	CENTE R	NPC	NUCLE AR	NUCLE AR		
43	M.A.P.P.	2	20-Sep-85	220	SR	TAMIL NADU	CENTE R	NPC	NUCLE AR	NUCLE AR		
118	VEMAGIRI CCCP	1	13-Jan-06	251.5	SR	ANDHRA PRADESH	PVT	VEMAGIRI	THERM AL	GAS	n/a	Yes-#4334
120	BELLARY TPS	1	3-Dec-07	500	SR	KARNATAKA	STATE	KPCL	THERM AL	COAL	OIL	