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

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Annexes

Appendices

SECTION A. General description of project activity

A.1 Title of the project activity:

>> "Grid connected electricity generation using natural gas by Lanco Kondapalli Power Private Limited."

Version 01

Dated: 20/01/2010

A.2. Description of the project activity:

Purpose of the project activity

The scope of the project activity involves implementation and operation of a new natural gas fired grid-connected Combined Cycle Power Plant (CCPP) of 366 MW capacity at Kondapalli near Vijayawada, Andhra Pradesh by Lanco Kondapalli Power Private Limited (LKPPL).

The proposed CCPP will operate on Brayton Cycle (Compressor & Gas Turbine) at top and Rankine Cycle (Heat Recovery Steam Generator & Steam Turbine) at bottom. The power generated from the project activity will be sold on merchant basis to the state utilities in Southern, Western & Northern India. The project employs state of the art technology with estimated project life of 20 years.

The project will comprise of the following major equipments:

- One advanced class, heavy duty, Gas turbine generator with a nominal output of about 234 MW at site condition and with Gas turbine Inlet air-cooling system under operation.
- One Heat Recovery, natural circulation, three pressure vertical type Steam Generator.
- One Steam Turbine Generator of around 132 MW (@ 30 deg C, 60% RH), multistage, intermediate injection, condensing, type.

The project activity is designed to use natural gas as main fuel for power generation. Natural gas will be sourced from the Krishna Godavari basin of Reliance Industries Limited (RIL). Gas Supply & Transportation Agreements have been executed with Reliance Industries Limited and Reliance Gas Transportation Infrastructure Limited, respectively, in this regard.

The power generated would be stepped up to 400 kV level by using 15/420 kV generator transformers. To enable the process a 400 kV Gas Insulated Switchgear (GIS) type substation will be provided. A double circuit 400 kV transmission line has been proposed to export power to 400 kV receiving end substation of the Power Grid Corporation of India Limited (PGCIL) located at Nunna.

The pre project scenario

The project activity is a new grid connected power plant. Hence the pre-project scenario will include generation of power from existing or proposed new power plants connected to the Southern 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 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.

Baseline Scenario

In accordance with the approved baseline methodology AM0029, version – 03 (based on approach 48b of the CDM modalities and procedures) baseline has been established considering "emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment". In line with this approach a detailed investment comparison analysis has been carried out in

section B.4 of this document considering the levelised cost of generation as the most suitable financial indicator.

In the present context it has been established that lignite based power station would be the economically most attractive alternative to the project activity and hence the most plausible baseline scenario. 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 involves power generation from the grid connected (Southern Regional Grid) gas based Combined Cycle Power Plant (CCPP). The technology employed in the project activity has been discussed in section A.4.3 of this document

The carbon intensity of the present project activity would be lower than the southern regional grid (as per Build Margin & Combined Margin) or the lignite based power station identified as the most plausible baseline option. Hence the project activity reduces CO2 emission by way of avoiding power generation from relatively higher carbon intensive sources.

The approved baseline methodology AM0029, version – 03 recommends the lowest emission factor amongst the following three options to be considered for ascertaining the emission reductions due to the project activity:

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

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

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

In the context of the present project activity the option 1 has been found to be the most conservative. Hence the build margin emission factor has been considered towards determining the emission reduction due to the present project activity. It has been discussed in detail in section B.6.1 of this document.

The description of the sources of greenhouse gases included in or excluded from the project boundary has been discussed in section B.3 of this document.

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

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

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.

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:

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

Technological well being:

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

The project proponent will contribute 2% of the revenue realized from sale of certified emission reduction arising from the candidate CDM project towards sustainable development including initiatives towards society / community development in line with the measures indicated in the sections above.

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)	Private Entity: Lanco Kondapalli Power Private Limited.	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

>> Village – Kondapalli, District – Krishna, Andhra Pradesh, India

A.4.1.1. Host Party (ies):

>> India

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

>> Andhra Pradesh

A.4.1.3. City/Town/Community etc:

>> Village – Kondapalli, District – Krishna

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

>>The proposed project activity will be located at Kondapalli Industrial Development Area in Andhra Pradesh. The project activity will be located in a plot of area 132 acres. Kondapalli railway station is approximately 1km from the site and the nearest Airport is at Gannavaram at about 35 kms from the plant. The proposed project site is at a latitude of 16°45’00” N and at a longitude of 80°35’00” E.

The location details are presented in **Appendix 1** of this document.

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

>> As per the scope of the project activity listed in the "List of Sectoral scopes" (Document CDM-ACCR-06 version 04)', the project activity will principally fall in Scope Number 1, Sectoral scope – energy industries (renewable/ non-renewable sources) being a Grid-connected electricity generating project using non-renewable fuel in energy industries.

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

>> The project activity construction and operation of a new natural gas fired grid-connected electricity generation plant.

Pre-project scenario:
Since the project activity is a new grid connected (Southern Region) power plant, the pre-project scenario includes generation of power from existing or proposed new power plants connected to the Southern regional grid or import of electricity from connected grids, including the possibility of new interconnections.

Project activity:

The scope of the project activity involves implementation and operation of a new natural gas fired grid-connected Combined Cycle Power Plant (CCPP). The project proposes to employ state of the art technology with estimated project life of 20 years . There is no technology transfer in this project activity. The table below provides the details of main equipment of the power plant:

S.No	Equipment	Specifications	Special Features
1.	GTG	Make : GE, USA GTG is of advanced class industrial heavy-duty type (Model 9FA) with dry low NO_x technology capable of operating in combined cycle mode, Nominal output capacity: 234 MW at site conditions (Dry Bulb Temperature - 32 deg. C; Design Wet Bulb Temperature - 25 deg. C; Relative Humidity (RH) = 70%)	Low NO_x technology along with state of the art cooling. Thermal efficiency close to 53 - 58% (LHV)
2.	STG	Make: Harbin, China One steam turbine generator of output capacity 132 MW at site condition (Dry Bulb Temperature - 32 deg. C; Design Wet Bulb Temperature - 25 deg. C; Relative Humidity (RH) = 70%)	• Multistage, intermediate injection, condensing type steam turbine. • State of the art DCS control system
3.	HRSG	Make: : Thermax , India Capacity: : HP/IP/LP Flow 282.79/ 42/34.26 TPH; temperature 567.3/567/286.6 DegC ; pressure 98.47/22.4/3.1 Bar	• Horizontal flue gas flow and natural circulation. • HRSGs are designed with three pressure stages to improve thermal efficiency, against conventional two pressure stages for similar application. • State of the art DCS control system.

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 power generated would be stepped up to 400 kV level by using 15/420 kV generator transformers. As to enable the process a 400 kV Gas Insulated Switchgear (GIS) type substation will be provided. A double circuit 400 kV transmission line has been proposed to export power to 400 kV receiving end substation of the Power Grid Corporation of India Limited (PGCIL) located at Nunna.

The necessary transmission lines for this purpose will be installed by LKPPL. The GTG is connected to the bus in the switchyard through a generator transformer that steps up voltage from 15 kV to 400 kV, provided with off load tap changers on the high voltage side. The STG is connected to the switchyard through a generator transformer that steps up voltage of 13.8 kV to 420 kV.

The project activity is designed to use natural gas as fuel for power generation. NG used as fuel for the project is likely to be a combination of NG and Regasified- Liquid Natural Gas ("**R-LNG**") Natural gas will be sourced from the Krishna Godavari basin of Reliance Industries Limited (RIL) through pipe line up to the project site. Gas Supply & Transportation Agreement have been executed with RIL & RGTIL respectively in this regard. A minimum gas pressure of 98 bar (a) at RIL terminal point will have to be maintained and the gas conditioned to meet the requirement of gas turbine fuel specification. The total gas requirement of the project activity has been estimated to be around 1.52 MMSCMD. The above requirement is based on 8563[1] kcal/SCM as net calorific value of gas and heat rate of 1850[2] kCal / kWh rate at generator terminal.

The green house gases emitted from project activity would include CO2 emissions due to on-site fuel combustion; CO2 and CH4 emissions due to Transportation of fuel to project site (inside the project boundary). The CO2 emissions due to Processing and transportation of fuel outside the project boundary are being accounted for as leakage emissions.

<u>Baseline scenario:</u>

Since the project activity is a new grid connected (Southern Region) power plant, the baseline scenario will include generation of power from existing or proposed new power plants connected to the southern regional grid or import of electricity from connected grids, including the possibility of new interconnections.

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 (as enlisted above) were evaluated based on investment comparison 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, a power plant (s) based on lignite as fuel has been established as the economically most attractive option

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 lignite as fuel) would emit higher CO2.

[1] Reference: Detailed Project Report

[2] Reference: Detailed Project Report

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

>> The estimated emission reductions over the 10 year fixed crediting period (2010-2020) would be 8,868,730 **tCO_{2e}** as per details on annual emission reductions provided below.

Years	**Annual estimation of emission reduction (tCO_{2e})**
2010 –2011	886,873
2011 –2012	886,873
2012 –2013	886,873
2013 –2014	886,873
2014 –2015	886,873
2015 –2016	886,873
2016 –2017	886,873
2017 –2018	886,873
2018 –2019	886,873
2019 –2020	886,873
Total estimated reductions (tCO_{2e})	8,868,730
Total number of crediting years	10
Annual average over the crediting period of estimated reductions (tCO_{2e})	886,873

A.4.5. Public funding of the project activity:

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

SECTION B. Application of a baseline and monitoring methodology

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

>> Approved baseline methodology AM0029 (version 03.0 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"**.

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

The project activity also refers to the "Tools to calculate the emission factor for an electricity system" (Version 01.1, EB 35).

The project activity also refers to the "Tool for the demonstration and assessment of additionality" (Version 05.2, EB 39).

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

>> The selected methodology AM0029 version 3.0 is applicable to the proposed CDM project activity. The project activity is the construction and operation of a new natural gas fired grid-connected (Southern grid) 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 startup or auxiliary fuels can be used, but can comprise no more than 1% of total fuel use, on energy basis.

The project activity involves construction and operation of a new natural gas fired grid-connected electricity generation plant, of 366 MW capacity. The only 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 southern[3] regional electricity grid, whose geographical/ physical boundaries can be clearly identified and information pertaining to the grid and estimating baseline emissions is available in public domain on the website of the Central Electric Authority of India http://cea.nic.in.

Natural gas is sufficiently available in the region or country, e.g. future natural gas based power capacity additions, comparable in size to the project activity, are not constrained by the use of natural gas in the project activity. In some situations, there could be price-inelastic supply constraints (e.g. limited resources without possibility of expansion during the crediting period) that could mean that a project activity displaces natural gas that would otherwise be used elsewhere in an economy, thus leading to possible leakage. Hence, it is important for the project proponent to document that supply limitations will not result in significant leakage as indicated here.

Production of natural gas in India is at present at the level of around 87 million standard cubic meters per day ("**MMSCMD**"). The main producers of natural gas are Oil & Natural Gas Corporation Ltd. ("**ONGC**"), Oil India Limited ("**OIL**") and JVs of Tapti, Panna-Mukta and Ravva. Out of the total production of around 87 MMSCMD, after internal consumption, extraction of Liquefied Petroleum Gas ("**LPG**") and unavoidable flaring, around 74 MMSCMD is available for sale to various consumers.

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

Most of the production of gas comes from the Western offshore area. The on-shore fields in Assam, Andhra Pradesh and Gujarat States are other major producers of gas. Smaller quantities of gas are also produced in Tripura, Tamil Nadu and Rajasthan States. OIL is operating in Assam and Rajasthan States, whereas ONGC is operating in the Western offshore fields and in other states. The gas produced by ONGC and a part of gas produced by the JV consortiums is marketed by the 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.

There have been discoveries in Krishna-Godavari (KG) basin[4] by – Reliance Industries Limited ("**RIL**") way back in 2002. RIL expected to produce @ 80 MMSCMD[5] (i.e.29.2 Billion Cubic Meter per year) with effect from 2009. RIL has also been constructing a cross country natural gas pipeline connecting eastern coast of India in Andhra Pradesh and Bharuch in Gujarat on western coast of India. State-owned Gujarat State Petroleum Corporation Limited ("**GSPCL**") has also struck gas in the Krishna Godavari basin, off Andhra Pradesh coast in the Bay of Bengal. This additional indigenous gas can be brought to Gujarat through the pipeline.

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

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

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

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 Southern region are as follows:

Supply Source (Southern 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. (East – West gas distribution network)	5	7142.85
Dhabol – imported re-gasified LNG. (East – West gas distribution network)	2.5	3571.429
Total	**-**	**39914.29**

For understanding the natural gas requirement of the future gas based power station in the Southern region, the table below gives a list of gas based power stations included in the 11th five year plan (2007 - 2012)[6] in the Southern Region and associated natural gas requirement therein. This estimation is based on a normative station heat rate of 1950 kCal /kWh[7] and at PLF of 80%[8].

Sl.No	Station	Capacity (MW)	Power generation (Million units/Year)	Gas requirement (Million SCM/Year)
1.	Gautami - CCPP ; Andhra Pradesh[9]	Gas Turbine – 290 Steam Turbine – 174	3251.71	667.18
2.	Koenseema CCPP ; Andhra Pradesh[10]	Gas Turbine 1 – 140 Gas Turbine 2 – 140 Steam Turbine – 165	3119	640
3.	Lanco Kondapalli - CCPP - Stage - II ; (Project Activity) Andhra Pradesh	Gas Turbine – 233 Steam Turbine – 133	2565	554.14 (assumed SHR 1850 kCal / kWh)
4.	Valuthur - GTPP; Phase II; Tamil Nadu[11]	Gas Turbine – 59.8 Steam Turbine – 32.4	646	133
Total			**9581**	**1994**

[6] http://www.cea.nic.in/

[7] CERC tariff order dated 26th March, 2004

[8] Detailed Project Report of the project activity

[9] http://www.cea.nic.in/thermal/project_monitoring/BS%20AP.pdf

[10] http://www.cea.nic.in/thermal/project_monitoring/BS%20AP.pdf

[11] http://www.cea.nic.in/thermal/project_monitoring/BS%20TN.pdf

Natural gas requirement by gas based power station in the Southern region including the project activity is 1994 million SCM per year against an availability of 39914.29 million SCM per year. It is apparent from the statistics presented above that the future gas supply in the Southern region would be adequate for meeting the fuel requirement of the gas based power stations as included in the 11th five year plan of 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.

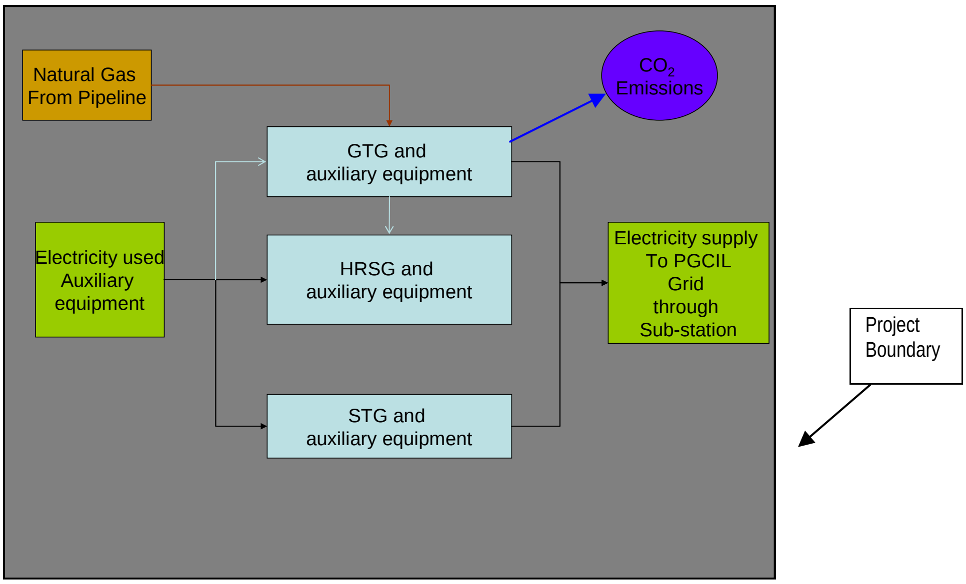
From the above discussion, it is apparent that the project activity satisfies all the applicability conditions of AM0029, version - 03.

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

>> The spatial extent of the project boundary includes the equipment that constitute the 366 MW CCPP at Kondapalli site of LKPPL as listed below and all power plants connected physically to the baseline grid as defined in "Tool to calculate the emission factor for an electricity system".

The equipments that form part of the project boundary are:

1. Gas Turbine Generator – 234 MW capacity
2. Steam Turbine Generator – 132 MW
3. GT/ST Generator & Unit aux. transformers – 290 MVA/190 MVA, 20 MVA.
4. Auxiliary equipments of Gas Turbine & Generator – Lube oil system, Air intake system, Evaporative cooling system, Exhaust system, Heat Recovery Steam Generator - Circulation Pumps, valves, HP/LP Bypass system, Piping etc.
5. Auxiliary equipments of Steam Turbine & Generator – Hydraulic and lube oil system, condenser, Feed Pumps, Condensate extraction pumps,



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

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

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

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation using coal/lignite/ naphtha as fuel	CO_2	Yes	Main emission source.
		CH_4	No	Excluded (conservative approach).
		N_2O	No	Excluded (conservative approach).
	Grid electricity generation in baseline	CO_2	Yes	Main emission source.
		CH_4	No	Excluded (conservative approach).
		N_2O	No	Excluded (conservative approach).
	Fuel processing and transportation	CO_2	No	Excluded (conservative approach).
		CH_4	No	Excluded (conservative approach).
		N_2O	No	Excluded (conservative approach).
Project Activity	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source.
		CH_4	No	Excluded for simplification.
		N_2O	No	Excluded for simplification.
	Transportation of fuel to project site (inside the project boundary)	CO_2	Yes	Maybe significant emission source for NG/ LNG. Excluded for solid fuels.
		CH_4	Yes	Maybe significant emission source for NG/ LNG. Excluded for solid fuels.
		N_2O	No	Excluded for simplification.
	Processing and transportation of fuel outside the project boundary	CO_2	Yes	Accounted for leakage. This has been considered for conservativeness and prohibitive barriers to monitoring.
		CH_4	No	
		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, version - 03 the approach 48 (b) of CDM modalities and procedures "*Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment*" is being used to determine the baseline scenario.

The plausible baseline scenarios, as required using Step 1 of "Identification of baseline scenarios" of the applied baseline methodology AM0029, are described below. 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 and technology choice trend in power generation in India, including addition of plants running on coal – sub critical technology; coal – super critical technology; lignite; naphtha;
2. Establishing similar new generation capacity power plant based on natural gas but with alternative technologies;
3. Establishing similar new generation capacity power plant based on nuclear energy;
4. Establishing similar new generation capacity with renewable energy sources e.g., wind, hydro based power generation in India;
5. Capacity additions to a number of existing power plants aggregating to the capacity of the project activity; and
6. Import of electricity from connected grids, including the possibility of new interconnections.

An important fact to note here is that the project activity power plant will be built as a Merchant Power Plant (MPP). It is connected to the Southern regional electricity grid. On analysing the installed

capacities connected to the southern grid as on 30th September, 2007, the pattern for fuel distribution[12] emerges as follows:

Power Generating Source	Hydro	Coal	Gas	Diesel	Total thermal	Nuclear	RES	Total
Total Installed Capacity (MW)	10646.18	15972.5	3586.3	939.32	20498.12	1100	5899.33	38143.63
Contribution to the total installed capacity (%)	27.91	41.87	9.40	2.46	53.74	2.88	15.47	100.00

It is apparent from the table above that the thermal generating sources are quite predominant in the Southern regional grid as against the other sources of power generation. The thermal generating sources are mainly based on coal followed by gas and diesel.

In line with the statistics discussed above the potential baseline alternatives available to the present project activity is summarised in the table below

Scenario	Potential alternative conditions	Permitted by regulations
1.	Project activity implemented as a project without the CDM revenue	Yes
2.	Power generation using Natural Gas as fuel and open cycle technology.	Yes
3.	New power plant (s) based on coal – sub-critical technology	Yes
4.	New power plant (s) based on coal – super-critical technology	Yes
5.	New power plant (s) based on lignite	Yes
6.	New power plant (s) based on naphtha	Yes
7.	New power plant (s) based on hydro power (run-of-river[13])	Yes
8.	New power plant (s) based on nuclear power	Yes
9.	New power plant (s) based on wind energy	Yes
10.	Import of electricity from connected grids, including the possibility of new interconnections	Yes

All the above options are permitted by regulations. Analysis of all these options for their suitability as a most probable baseline scenario is presented in the sections below. For all the plausible options, levelized cost of electricity generation has been calculated in INR/kWh. The detailed levelized tariff calculations of all fuel/ technology options will be made available to the DOE during validation.

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

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 %) 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.

[12] http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_09/24-30.pdf

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

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 (Rankine Cycle), which is called a combined cycle (Gas and steam turbine operation). Thus HRSG and STG increase the overall energy cycle efficiency to around 50 %[14]).

Scenario 2: Power generation using Natural Gas as fuel and open cycle technology.

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[15] %) when utilized as an Open (simple) cycle. This very low efficiency makes open cycle gas turbine based power generation as a non-plausible baseline option and thus this option has not been discussed any further in the PDD.

Scenario 3: Power generation using coal as fuel – sub critical technology

Technology: Fossil fuel-fired (coal) power plants use steam to provide the mechanical power to electrical generators. Pressurized high temperature steam or gas expands through various stages of a turbine, transferring energy to the rotating turbine blades. The turbine is mechanically coupled to a generator, which produces electricity. Steam turbine power plants operate on a Rankine cycle. The steam is generated by a boiler, where pure water passes through a series of tubes to capture heat from the furnace and then boils under high pressure to become superheated steam. The heat in the furnace is normally provided by burning fossil fuel (e.g. coal, fuel oil etc). The coal is fed to boiler after pulverization in the coal mills. The pulverized coal is transported to burners through primary air which is heated in Air 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 remains around 33 to 38%.

Scenario 4: Power generation using coal as fuel with super-critical technology

Technology: Super critical technology is almost similar to the sub critical technology explained in the Scenario 2 except that the super critical steam generators operate at "supercritical pressure". In contrast to a "sub-critical boiler", a supercritical steam generator operates at such a high pressure (over 3200 PSI, 22 MPa, 220 bar) that actual boiling ceases to occur, and the boiler has no water - steam separation. There is no generation of steam bubbles within the water, because the pressure is above the "critical pressure" at which steam bubbles can form. It passes below the critical point as it does work in the high pressure turbine and enters the generator's condenser. This is more efficient,

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14 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

15 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

resulting in slightly less fuel use and therefore less greenhouse gas production. The term "boiler" should not be used for a supercritical pressure steam generator, as no "boiling" actually occurs in this device. Differences between sub critical and super critical power plants are limited to a relatively small number of components; primarily the feed water pumps and the high-pressure feed water train equipment. All the remaining components are common to sub critical and super critical coal-fired power plants. Super critical technology also follows the same Rankine cycle. Steam generated from the generator will be allowed to expand in the Steam turbine and thus producing the work. The power plant cycle efficiency is in the range of 36 % to 43%. Since the efficiency of the super critical technology is better, the coal consumption and ash / pollution generated are also less compared with the sub critical technology. However the capital cost for the super critical technology is much higher.

Scenario 5: Power generation using lignite as fuel

Technology: Fuel combustion in Circulating Fluid Bed system takes place in a vertical chamber referred to as the Combustor, in which the fluidisation of the fuel and the fuel combustion takes place. The fuel is preheated before entry and burnt at 850°C. The particle size of fuel used at bed is typically in the range of 50-300 microns. The bed material is fluidized by preheated primary air introduced through a grate at the bottom of the bed and by the combustion gases generated which flow upwards at a relatively high fluidizing velocity. The entire combustor contains a high concentration of suspended solids, which decrease continuously towards the top of combustor. The combustion gas entrains a considerable portion of the solids inventory from combustor. The bulk of these entrained solids is separated from the gas in the cyclone and is continuously returned to be bed by recycle loop. The very high internal and external circulating rates of solids, characteristics of the Circulating Fluid Bed, result in consistently uniform temperatures throughout the combustor and the solids recycle system. The long residence and contact times, coupled with the small particle sizes and efficient heat and mass transfer rates, produce high combustion efficiency. The relatively high ratio of solids circulation to fuel feed means that the Combustor is largely full of recycled solids and actual carbon content is surprising low. Further the large thermal inertia of the recycled solids allows the CFB system to handle high ash or high moisture fuels better than conventional combustion systems. Combustion of low volatile fuels like coke breeze in a CFB system is therefore more stable and of high efficiency. Combustion air is introduced into the combustor at multiple levels. About forty percent of the combustion air is passed as primary fluidizing air through the grate at the bottom and the balance is admitted as preheated secondary air through multiple ports in the side walls of the combustor. Combustion therefore occurs in two zones: a primary reducing zone in the lower section of the combustor, and complete combustion using excess air via the secondary air ports in the upper section. This staged combustion at controlled low temperatures of around 850°C, effectively suppresses NO_x formation. The entire combustor as well as the grate is enclosed by water walls and the lower water wall section is refractory lined to prevent corrosion and attack of the metal surfaces. The upper water wall section is not refractory lined and provides the majority of the evaporative duty of the boiler. The bottom ash discharged from the combustor is at 850°C and so it needs to be cooled in an ash cooler to approx. 200-250°C. The fly ash separated in the back pass and air pre heater and the fly ash from the ESPs are collected in the hoppers. The steam from the steam generator is fed to turbine for power generation and turbine and other systems are similar to that of conventional Thermal Power plant.

Scenario 6: 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 366 MW has been considered. Naphtha fired gas turbine power 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 %[16] 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%[17]

Scenario 7: Power generation using hydro power

Technology: In the last five years the following hydel energy based power plants have been added to the southern grid[18]:

S.No.	Power Plant Name	Unit	State	Date of Addition	Capacity (MW)
1.	Srisailam LBPH	3	Andhra Pradesh	29-Mar-02	150
2.	Srisailam LBPH	4	Andhra Pradesh	30-Nov-02	150
3.	Srisailam LBPH	5	Andhra Pradesh	28-Mar-02	150
4.	Srisailam LBPH	6	Andhra Pradesh	04-Sep-03	150
Total – Andhra Pradesh					**600**
1.	Sharavathy Tail Race	4	Karnataka	30-Mar-02	60
2.	Jog	8	Karnataka	30-Oct-02	21.6
3.	Madhavamantri	1	Karnataka	31-Mar-03	1.5
4.	Madhavamantri	2	Karnataka	31-Mar-03	1.5
5.	Madhavamantri	3	Karnataka	31-Mar-03	1.5
6.	Almatti Dam	1	Karnataka	26-Mar-04	15
7.	Almatti Dam	2	Karnataka	4-Nov-04	55
8.	Almatti Dam	3	Karnataka	13-Jan-05	55
9.	Almatti Dam	4	Karnataka	26-Mar-05	55
10.	Almatti Dam	5	Karnataka	6-Jul-05	55
11.	Almatti Dam	6	Karnataka	10-Aug-05	55
Total – Karnataka					**376.1**
1.	Chembukadavu-II	1	Kerala	25-Jan-04	1.25
2.	Chembukadavu-II	2	Kerala	25-Jan-04	1.25
3.	Chembukadavu-II	3	Kerala	25-Jan-04	1.25
4.	Urumi	1	Kerala	25-Jan-04	1.25
5.	Urumi	2	Kerala	25-Jan-04	1.25
6.	Urumi	3	Kerala	25-Jan-04	1.25
Total – Kerala					**7.5**
1.	Pykara Alimate	1	Tamil Nadu	11-Aug-05	50
2.	Pykara Alimate	2	Tamil Nadu	11-Aug-05	50
3.	Pykara Alimate	3	Tamil Nadu	5-Sep-05	50
4.	Bhawani Kattalai Barrage	1	Tamil Nadu	1-Aug-06	15

16 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

17 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

18 http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm; baseline CO2 emission database, version - 04

S.No.	Power Plant Name	Unit	State	Date of Addition	Capacity (MW)
5.	Bhawani Kattalai Barrage	2	Tamil Nadu	22-Sep-06	15
Total Tamil Nadu					**180**
Total Southern Region					**1163.6**

This data indicates that out of the entire capacity of 1163.6 MW of hydro power plant, 88% (1025 MW) has been with 50 MW plus size with storage hydro thereby catering to the peak-in load rather than base load of the grid.

On the contrary the project activity is a gas based MPP. Depending upon the requirement, the project activity power plant would provide steady supplies to the grid and also could be used to meet the grid demand during peak loads. This makes run-of-the-river hydro energy based power generation as a non-plausible baseline option.

Scenario 8: 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.	Kaiga Generating station –III	Nuclear Power Corp. Ltd.	220	6 May 2007
2.	Tarapur Atomic Power Station 3	Nuclear Power Corp. Ltd.	540.00	18 August 2006
3.	Tarapur Atomic Power Station 3	Nuclear Power Corp. Ltd.	540.00	12 September 2005

The nuclear energy based power generation in India does not fall in the purview of CERC/ SERCs and the tariff is unilaterally decided by Nuclear Power Corp. Ltd. There is no verifiable source of information available in public domain on the unit cost of power generation using nuclear energy. The levelized tariff of generation from nuclear energy is, however, higher than that from coal by about 15%[19] and also this option is not available to a private investor and hence has been excluded as a baseline option.

Scenario 9: Power generation using wind energy

The proposed project activity is a gas based MPP without any PPA being executed for power off-take. In absence of PPA as with traditional independent power projects, the project activity would compete for customers and absorb full market risks. Depending upon the requirement, the project activity power plant would provide steady supplies to the grid and also could be used to meet the grid demand during peak loads.

Wind power generation will not qualify as a source of "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. Moreover unlike present project activity wind power projects are always governed by long term PPA.

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.

Scenario 10: Import of electricity from connected grids, including the possibility of new interconnections

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

The actual power supply position during the period April – September, 2007[20] is as follows

Regional Grid	Northern Region	Western Region	Southern Region	Eastern Region	North – Eastern Region
Power Requirement (Million Units)	112,411	111,517	91,242	37,868	4,421
Power Availability (Million Units)	104,707	97,960	89,252	36,645	3,911
Surplus / Deficit (-)	(-)7,704	(-)13,557	(-)1,990	(-)1,223	(-)510

It remains implied from the statistics furnished 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 the regional grid. 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

Given the grid data of last 3 years, all the regional grids are power deficit. It makes import of electricity from the interconnected grids not a plausible baseline option.

The above analysis of the 10 alternatives available to a company investing in power generation for supply of base load power to Southern regional grid in India leads to following alternatives:

Scenario 1: Power plant based on natural gas using CCPP technology

Scenario 3: Power plant based on coal using sub-critical technology

Scenario 4: Power plant based on coal with super-critical technology

Scenario 5: Power plant (s) based on lignite

Scenario 6: Power plant (s) based on naphtha

For these five alternatives, the economically most attractive option has been evaluated in Step-2 in the following section.

Step 2 "**Identify the economically most attractive baseline scenario alternative"** of 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."*

LKPPL 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

[20] http://www.cea.nic.in/power_sec_reports/Executive_Summary/2007_09/20.pdf

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[21] is the evaluation criteria.

Levelized Tariff Analysis

For the scenarios 1,3,4,5 and 6 discussed 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[22] as per the guidelines prescribed by Central Electricity Regulatory Commission (CERC)[23]:

1. Return on Equity (ROE) at 14% as per CERC regulation
2. Debt: Equity ratio of 75:25.
3. Operation & Maintenance expenses: 2.5% of the capital cost (This is inclusive of employee cost, repairs and maintenance charges and administrative and general charges).
4. O&M escalation at 4%.
5. Depreciation inclusive opening gross fixed assets and average additions during the year at 3.6%
6. Interest on loan at 11.5% as per the DPR
7. Interest on working capital (WC): 11.50% as per the DPR
8. Normative Plant Load Factor (PLF) at 80%
9. Discount factor of 10 % as per CERC order
10. Tax on income at 33.66% as per Income Tax Act
11. MAT rate for the first 10 years considering 80IA benefit at 11.33% as per Income Tax Act

The variable cost has been calculated based on the cost of the fuel.

Levelized tariff for gas: The levelized tariff comes out as **INR 2.74/ kWh**. This has been calculated based on the following factors:

Capacity in MW	366	Aux. Consumption	3%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	1850
Per MW Cost (INR million)	32.46	Price of Fuel (INR/SCM)	7.87
Total Debt (INR million)	8910	NCV (kCal / SCM)	8,563
Total Equity (INR million)	2970	O&M Expenses (% of capital cost)	2.5%

21 http://powermin.nic.in/whats_new/competitive_guidelines.htm

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

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

Levelized tariff for coal with sub-critical technology:

The levelized tariff for power generation with coal comes out as **INR 2.14/ kWh**. This has been calculated based on the following factors:

Capacity in MW	500	Aux. Consumption	7.5%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	2450
Per MW Cost (INR million)	40	Price of Fuel (Rs / kg)	1.30
Total Debt (INR million)	15000	NCV (Kcal/kg) –	3755
Total Equity (INR million)	5000	O&M Expenses (lacs per MW/yr)	11.84

Levelized tariff for domestic coal with super-critical technology:

The levelized tariff for power generation with coal on Super critical technology comes out as **INR 2.20/ kWh**. This has been calculated based on the following factors:

Capacity in MW	660	Aux. Consumption	9.00%
Rate of Depreciation	3.60%	GSHR (kcal/kWh)	2228
Per MW Cost (INR million)	44.00	Price of Fuel (Rs / kg)	1.93
Total Debt (INR million)	21780	GCV (Kcal/kg)	5400
Total Equity (INR million)	7260	O&M Expenses (lacs per MW/yr)	11.84

Levelized tariff for lignite:

The levelized tariff for power generation with lignite comes out as **INR 2.07 /kWh**. This has been calculated based on the following factors:

Capacity in MW	500	Aux. Consumption	9.50%
Rate of Depreciation (up to 90%)	3.60%	SHR (kcal/kWh)	2695
Per MW Cost (INR million)	40.60	Price of Fuel (Rs/ kg))	0.78
Total Debt (INR million)	15225	NCV (Kcal/kg)	3,097
Total Equity (INR million)	5075	O&M Expenses (per MW/yr)	13.16

Levelized tariff for naphtha:

The levelized tariff for power generation with naphtha comes out as **INR 4.11 / kWh**. This has been calculated based on the following factors:

Capacity in MW	366	Aux. Consumption	3.00%
Rate of Depreciation (up to 90%)	3.60%	GSHR (kcal/kWh)	1850
Per MW Cost (INR million)	32.59	Price of Fuel (Rs/kg)	17.40
Total Debt (INR million)	8946	NCV (Kcal/kg)	10500
Total Equity (INR million)	2982	O&M Expenses (% of capital cost)	2.50

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

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
1.	New power plant (s) based on natural gas	2.74
2.	New power plant (s) based on coal with sub-critical technology	2.14
3.	New power plant (s) based on coal with super-critical technology	2.20
4.	New power plant (s) based on lignite	2.07
5.	New power plant (s) based on naphtha	4.11

Option 4, power generation plant based on lignite as fuel is clearly the most attractive option. Levelized tariff under option 1 i.e. the project activity implemented without considering the CDM revenue is amongst the more costly generation sources.

A sensitivity analysis was performed on the data above for the following factors to corroborate the conclusions drawn from the analysis above.

1. Total project cost: Increase and decrease by 10%.
2. Station Heat Rate (SHR): Increase and decrease by 10%.
3. Fuel price: Increase and decrease by 10%.
4. Plant Load Factor (PLF): increase and decrease by 10%.

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

Project Cost	Project Cost -10%	Project Cost +10%
Gas	2.6662	2.8212
Coal – Sub-critical	2.0513	2.2256
Lignite	1.9797	2.1605
Super Critical Coal	2.1030	2.2979
Naphtha	4.0349	4.2055

Station Heat Rate (SHR)	SHR - 10%	SHR +10%
Gas	2.5474	2.9280
Coal– Sub-critical	2.0432	2.2337
Lignite	1.9922	2.1480
Super Critical Coal	2.1098	2.2911
Naphtha	3.7802	4.4336

Fuel Price	Fuel Price -10%	Fuel Price +10%
Gas	2.5474	2.9280
Coal– Sub-critical	2.0440	2.2330
Lignite	1.9930	2.1471
Super Critical Coal	2.1106	2.2903
Naphtha	3.7802	4.4336

Plant Load Factor (PLF)	PLF -10%	PLF +10%
Gas	2.8304	2.6618
Coal– Sub-critical	2.2629	2.0367
Lignite	2.2018	1.9623
Super Critical Coal	2.3368	2.0890
Naphtha	4.2002	4.0305

From the data presented above, it can be observed that with variations in total project cost , SHR, fuel price and PLF baseline alternative using lignite as fuel continues to remain the economically most attractive options and natural gas as fuel remains more expensive option. Hence it substantiates that the project activity is not the economically most attractive route for power generation.

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 will use natural gas, a comparatively less GHG intensive fuel compared to other fossil fuels like coal, lignite, 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 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 similar projects there is no restrictions on utilization of any fuel for Grid Connected Generating stations. Therefore, the alternative to the project activity that could have been installed include either of the following fuels, viz. Coal, Lignite, Naphtha, etc. with conventional technologies.

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

Steps for Additionality Check

The Project start date is prior to the date of validation of the PDD. The justification as to demonstrate the serious consideration of CDM in line with the "Guidance on the demonstration and assessment of prior consideration of CDM" (EB41, Annex- 46)[24] is as follows.

The paragraph 5 (a) of the "Guidance on the demonstration and assessment of prior consideration of CDM" entails project proponent to indicate awareness of the CDM prior to the project activity start date and that the benefits of the CDM were a decisive factor in the decision to proceed with the project. The extract of the Board Resolution dated 15th October, 2007 evidently justifies that LKPPL was aware of CDM and had considered CDM revenue while according approval to the project investment. The extract of the Board Resolution would be submitted to DOE during validation.

The paragraph 5 (b) of the "Guidance on the demonstration and assessment of prior consideration of CDM" entails project proponent to indicate the continuing and real actions towards CDM implementation in parallel with project implementation have been undertaken by LKPPL. In order to justify the same an implementation timeline of the proposed CDM project activity along with the chronology of events is presented in the table below:

Sl. No.	Milestone	Date	Reference[25]
01.	News paper advertisement on Request for Quotation (RFQ) & Request for Proposal (RFP) towards awarding EPC contract.	24th September, 2007	The news paper advertisement
02.	Service order for preparation of feasibility –cum-detailed project report.	27th September, 2007	The feasibility –cum-detailed project report.
03.	Extract of the Board Resolution evidencing CDM revenue has been	15th October, 2007	The extract of the Board Resolution.

[24] http://cdm.unfccc.int/EB/041/eb41_repan46.pdf

[25] All the required evidences will be submitted to the DOE during validation

Sl. No.	Milestone	Date	Reference[25]
	seriously considered in the decision to go ahead with the project activity.		
04.	Information Memorandum placed to Financial Institution (FI).	2nd April, 2008	The relevant section of the Information Memorandum.
05.	Execution of the EPC agreement. (The project activity start date).	30th January, 2008	The EPC agreement.
06.	Appointment of CDM consultant.	5th June, 2008	The CDM advisory agreement.
07	Gas supply agreement with RIL	29th August, 2009	The gas supply agreement
08.	Achieving financial closure	14th November, 2008	The relevant section of the loan sanction letter as received from the FI.
09.	Invitation letter for stakeholders' consultation meeting.	22nd December, 2008	The invitation letter.
10.	The stakeholders' consultation meeting.	6th January, 2009	The minutes of the stakeholders' consultation meeting.
11.	Submission of the project to MoEF as to obtain HGA.	3rd March, 2009	The application letter to MoEF.
12.	Execution of the operation & maintenance agreement.	15th July, 2009	The EPC agreement.
13.	Communication sent to DOEs requesting offers to carry out CDM validation.	14th August, 2009	Copy of the e-mail communication between LKPPL and the DOE.
14.	Communication with another CDM consultant.	August, 2009	E-mail communications
15.	Appointment of new CDM consultant	26th October, 2009	Contract document
16.	Expected date of project commissioning.	1st December 2009 (in open cycle) 31st March 2010 (in combined cycle)	Commissioning certificate

It remains apparent from the above discussion that in tandem with the actual project implementation activities LKPPL has taken initiative on continuous basis to secure CDM status of the project activity. Hence it substantiates that CDM has been seriously considered by LKPPL in their decision to go ahead with the project activity.

Step 1: Benchmark Investment analysis

Demonstrate that the proposed CDM project activity is unlikely to be financially attractive by applying sub-steps 2b (Option II: Apply investment comparison analysis), Sub-step 2c (Calculation and comparison of financial indicators), and 2d (Sensitivity Analysis) of the version 05 of the "Tool for demonstration assessment and of additionality" agreed by the CDM Executive Board.

To determine whether the proposed project activity is economically or financially less attractive than the other alternatives without the CDM revenues, the sub-steps 2b, 2c and 2d have been followed as required under AM0029, version 03.

Sub-step 2(b): Investment Comparison Analysis (Option II)

Based on Option III of sub-step (2b), the indicator that has been selected for benchmark analysis is the levelized tariff from power generation in INR/kWh. As explained under baseline scenario analysis, for power generation projects, levelized tariff was found to be the most suitable indicator.

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

The levelized tariff for all the plausible options to the proposed project activity has been calculated and presented in Section B.4 above. A summary of these levelized tariff[26] calculations is presented in the table below:

S.No.	Baseline Scenario	Levelized Tariff (INR/kWh)
1.	New power plant (s) based on natural gas	2.74
2.	New power plant (s) based on coal – sub-critical	2.14
3.	New power plant (s) based on coal with super-critical technology	2.20
4.	New power plant (s) based on lignite	2.07
5.	New power plant (s) based on naphtha	4.11

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

The Cost of Power Generation using lignite as fuel is considered as the benchmark, as this is the economically most viable option to the project proponent.

Sub-step 2d (Sensitivity Analysis)

The findings of sensitivity analysis on levelized tariff for power generation using natural gas, coal, (sub-critical & super-critical) lignite & naphtha were presented in section B.4 above. It further substantiates that even with reasonable variations in the key variable e.g. project cost, fuel price, SHR and PLF, power generation using natural gas as fuel continues to remain more expensive alternative and the same using lignite as fuel is the economically most attractive option.

Step 2: Common practice analysis

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

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

The subsequent paragraphs provide an analysis of "Other Activities (implemented or underway) similar to Project Activity" based on parameters such as region and broad technology; regulatory regime:, project technology; access to financing; and investment climate.

Region and broad technology:

The Indian power system is divided into five independent regional grids, namely Northern, Eastern, Western, Southern, and North-Eastern. The Northern, Eastern, Western and North-Eastern (NEWNE) grids have been connected together to form the NEWNE grid. As the Project Activity is located in the Southern Grid, we would consider Other Activities that are in the Southern Grid. Further, as the Project Activity employs combined cycle gas turbine (CCGT) technology, we have considered Other Activities as CCGTs operating or under implementation during the year 2007 ((As of 21st June, 2007)) around when the investment decision for the project activity was being approved..

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

Out of 118 thermal power plants in the Southern grid in 2006 – 07 (As of 21st June, 2007), there were 16 power plants implemented in the Southern Grid using CCGT technology[27]. These plants are listed in the Table below:

S.No.	Power Plant Name (Sector)	Capacity	Location	Implemented/under implementation in 1991-92	Multi-fuel or single fuel (natural gas)	Gross Generation 2004 – 05 (GWh)
Activities Implemented by 2004-05						
1.	Vijeswaran GT 1,2,3,4,5 (State)	272.3	Andhra Pradesh	Yes (1990- 98)	Multi-fuel (gas & naphtha)	1,992
2.	Jegurupadu GT 1,2,3,4,5,6 (Private)	455.4	Andhra Pradesh	No (1996-2005)	Multi-fuel (gas & naphtha)	1,424
3.	Godavari GT 1,2,3,4 (Private)	208	Andhra Pradesh	No (1997-1998)	Multi-fuel (gas & naphtha)	1,373
4.	Kondapalli GT 1,2,3 (Private)	350	Andhra Pradesh	No (2000)	Multi-fuel (gas & naphtha)	2,246
5.	Peddapuram CCGT (Private)	220	Andhra Pradesh	No (2000)	Multi-fuel (gas & naphtha)	1,178
6.	Tanir Bavi 1,2,3,4,5 (Private)	220	Karnataka	No (2001)	Multi-fuel (gas & naphtha)	661
7.	Kayam Kulam GT 1,2,3 (Center)	350	Kerala	No (1998-1999)	Multi-fuel (gas & naphtha)	621
8.	Valuthur GT 1 (State)	95	Tamil Nadu	No (2002-2003)	Single (natural gas)	558
9.	Kuttalam GT 1,2 (State)	100	Tamil Nadu	No (2003-2004)	Single (natural gas)	641
10.	Kovilkalappal (State)	107	Tamil Nadu	No (2000-01)	Single (natural gas)	763
11.	P.Nallur CCGT (Private)	330.5	Tamil Nadu	No (2000-01)	Multi-fuel (gas & naphtha)	478
12.	Karuppur GT 1,2 (Private)	119.8	Tamil Nadu	No 2004-05	Single (natural gas)	0
13.	Karaikal (State)	32.5	Tamil Nadu	No (1999 - 2000)	Single (natural gas)	275
14.	Nariman GT 1,2 (State)	10	Tamil Nadu	Yes (1991-92)	Single (natural gas)	0
15.	Valantharvi GT 1 (State)	38	Tamil Nadu	No 2005 - 06	Single (natural gas)	0
16.	Vemagiri CCCP 1 (Private)	233	Andhra Pradesh	No (2005 - 06)	Single (natural gas)	0

During 2004–05, the operating gas based units generated 12,210 GWh compared to the total generation of 146486.90 GWh in Southern Grid[28]. This implies a penetration of 8.33%, i.e., a significant majority of the electricity generation (91.66%) has been from non-CCGT plants. This includes electricity generation from a major share of conventional pulverized fuel fired coal based and lignite based power plants (99,009.99 GWh or 67.59% of the Southern Grid generation).

[27] Source: CEA CO2 Baseline Database, Version - 02
http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

[28] Source: table 3.4 of CEA General Review 2006;
http://cea.nic.in/power_sec_reports/general_review/0405/index.pdf,

Regulatory regime:

Government of India came out with a policy for private sector participation in generation of electricity in Oct 1991[29]. Prior to that, only state and federal governments, the entities promoted by the state/federal governments and select private licensees (Tata Power, BSES, etc.) which were not nationalized under the Indian Electricity Act 1910 were allowed to invest in power sector generation. 2 out of the 16 CCGT power plants mentioned above were implemented or under implementation when the new 1991 policy was announced. As these 2 projects enjoyed special status (for having exclusive right to invest in power generation projects) under the pre-1991 regulatory framework, these are excluded from being part of Other Activities. The remaining 14 power plants contributed to generation of 10,903 GWh (Vijeswaran GT - Unit 1, 2 & 4 & Nariman GT –Unit – 1&2 have been considered as the station prior to 1991) in 2004 – 05 or a penetration of 7.44%[30].

Technology:

Out of the remaining 15 power plants mentioned above, 7 power plants (Jegurupadu GT 455.4 MW; Godavari GT 208 MW ; Kondapalli GT 350 MW; Peddapuram CCGT 220 MW; Tanir Bavi 220 MW; P.Nallur CCGT 330.5 MW and Kayam Kulam GT 350 MW) have multi-fuel firing capabilities. Multi-fuel fired CCGTs are not only technologically different (burner design, storage tanks, pipelines, etc.) but also have greater flexibility to choose within a range of fuels, depending on economics and availability and are thus better able to diversify fuel risks and dispatch risks, as compared to single (natural gas) fired plants. Thus, these multi-fuel fired are excluded from Other Activities. The remaining 7 Other Activities that are similar to the Project Activity generated 2,108 GWh or 1.99% of the total Southern Grid generation[31].

Access to financing:

Valuthur GT 95 MW; Kuttalam GT 100 MW; Kovilkalappal 107 MW ; Karaikal 32.5 MW & Valantharvi GT 38 MW are set up by Tamil Nadu Electricity Board and owned by the State Government of Tamil Nadu.

The private sector gas based power projects commissioned in last 5 years that are connected to the southern regional grid are as follows:

Power Plant	Date of commissioning	Power Plant Capacity (MW)	CDM Status[32]	Owner
Jegurupadu GT; Unit No 5&6	Unit 5 – 9h Oct - 2005 Unit 6 – 11th Nov - 2005	Unit 5 – 140 Unit 6 – 80	Validation	GVK Industries Limited
Peddapuram CCGT 1	26-Jan-02	220	Validation	Reliance Energy Limited
Karuppur GT, Unit 1 & 2	Unit 1 – 19th Feb-2005 Unit 2 – 15th Jul-2005	Unit 1 – 70 Unit 2 – 49.2	Registered (Reference	Aban Power Company

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

[30] Source: CEA Database http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

[31] Source: CEA Database http://cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

[32] http://www.cdmpipeline.org/publications/CDMpipeline.xls

Power Plant	Date of commissioning	Power Plant Capacity (MW)	CDM Status[32]	Owner
			No. 0999)	Limited
Vemagiri CCPP	13th Jan - 2006	233	Validation	Vemagiri Power Generation Ltd

Hence it is quite evident from the above analysis that all the project activities similar to the present project activity had followed the CDM route and at various stages of CDM project cycle. Hence all these projects are excluded from further consideration following the guideline stipulated in sub-step 4a of tool for demonstration and assessment of additionality.

Moreover, the project activity has been proposed to be built up as a Merchant Power Plant (MPP) and is not governed by long term Power Purchase Agreement (PPA). The project proponent is aiming to sell the entire power generated by the project activity on merchant basis to the state utilities in Southern, Western & Northern India.. In absence of PPA for power offtake as with traditional independent power projects, the project activity would compete for customers and absorb full market risks. Depending upon the requirement, the project activity power plant would provide steady supplies to the grid and also could be used to meet the grid demand during peak loads.

In India the project activity is the first of its kind gas based CCPP designed to sell power on merchant basis. In this regard the project activity is quite susceptible to issues like nature of its sale contracts, pricing of merchant power and regulatory risk, development of adequate transmission corridor for evacuation of merchant power and benign policy framework for the development of merchant plants.

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

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

Step 3: Impact of CDM registration

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

The latest version of “Tool for demonstration assessment and of additionality” version 05 EB39 has done away with Step 5 and therefore this has not been analysed.

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

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

>> According to the approved baseline methodology AM0029, the emission reductions ER_y by the project activity is calculated using the equation number 6 of version 03 (EB 39)

$ER_y = BE_y – PE_y – LE_y$

Where:

ER_y : emissions reductions in year y (tCO2e)

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

PE_y : emissions in the project scenario in year y (tCO_2e)

LE_y : leakage in year y (tCO_2e)

Baseline emissions

Baseline emissions are calculated, using equation number 2 of AM0029 ver 03, by multiplying the electricity generated in the project plant ($EG_{PJ,y}$) with a baseline CO_2 emission factor ($EF_{BL,CO2,y}$), as follows:

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

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 lignite as fuel is the economically most attractive baseline alternative.

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 the emission factor for an electricity system”; and

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

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

$$EF_{BL,CO2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh \textit{ (using equation number 3 of AM0029 ver 03)}$$

where,

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

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

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

Option 1: Build Margin, calculated according to “Tool to calculate the emission factor for an electricity system”

The Build Margin emission factor $EF_{grid,BM,y}$ (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:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

(using equation number 12 of Tool to calcúlate the emission factor for an electricty system)

Where

$EF_{grid,m,y}$ 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)

$EF_{BL,m,y}$ 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[33] 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 the emission factor for an electricity system". We have, therefore, used the Operating Margin and Build Margin data published in the CEA database, version – 5.0 for calculating the baseline emission factor.

The Build Margin for the southern regional grid for year 2008-09 as per CEA database, version – 5.0 is **0.818 tCO2e/MWh**.

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

The combined margin emission factor as per "Tool to calculate the emission factor for an electricity system", 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 the emission factor for an electricity system", dispatch data analysis should be the first methodological choice. However, this option is not selected because the information required for calculating OM based on dispatch data is not available in the public domain for the Southern electricity regional grid.

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

[33] http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

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

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

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

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

Year	Operating Margin (tCO_2e/MWh)
2006 – 07	0.999
2007 – 08	0.991
2008 – 09	0.973
Average of 3 years	**0.988**

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 0.988 tCO_2e/MWh. As mentioned earlier, the applicable Build Margin value is 0.818 tCO_2e/MWh.

Applying a 50/50 weightage to the values for operating margin and build margin emission factors provided in the CEA database, the Combined Margin emission factor is calculated as **0.894 tCO_2e/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, lignite based power generation represents the economically most attractive course of action, taking into account barriers to investment. Therefore, lignite based power generation has been identified as the baseline scenario.

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

$$EF_{BL,CO2}(tCO_2/MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6GJ/MWh$$

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

Based on India's first national communication to United Nations, $COEF_{BL}$ = 106.15 tCO_2/TJ = 0.106 tCO_2/GJ

η_{BL} = 30.53% (refer Annex 3 for calculations) for lignite based power plants

$EF_{BL,CO2}(tCO2/MWh)$ = 0.106 (tCO2e/GJ) x 3.6 (GJ/MWh)/ 30.53%

= 1.25 tCO2e/MWh

Baseline Emission Factor

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

Option	Emission Factor (tCO_2e/MWh)
Option 1: Build Margin	0.818
Option 2: Combined Margin	0.895
Option 3: Emission factor of lignite based power plant	1.25

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 0.818 tCO2e/MWh.

As per AM0029, in case the Build Margin or the Combined Margin is selected as the baseline emission factor, the baseline emission factor (Build Margin) will be determined *ex-post*, as described in “Tool to calculate the emission factor for an electricity system”. As per “Tool to calculate the emission factor for an electricity system”, 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 November 2009 and contains information up to 2008-09. CEA has acknowledged that because of the dynamic nature of data, the database will have to be updated every year. Therefore we expect the CEA database to be updated every year. If the CEA database is not updated, the Build Margin number will be calculated by the project proponent using the available 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:

$$PE_y = \sum_f FC_{f,y} * COEF_{f,y} \quad \text{(using equation 1 of AM0029 ver 03)}$$

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:

$$COEF_{f,y} = \sum NCV_y * EF_{CO_2,f,y} * OXID_f \quad \text{(using equation 1a of AM0029 ver 03)}$$

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: 8563 kCal/SCM or 35851.57 KJ/SCM

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

IPCC default value for Carbon Emission Factor of Natural Gas is 56.10 tCO_2e/tJ

$EF_{CO2,f,y}$ = 56.10 tCO_2e/tJ

$OXID_f$: Oxidation factor of Natural Gas as per IPCC Guidelines is 1.0

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

$COEF_{f,y}$ = 35851.57/10^9 (tJ/SCM) x 56.10 (tCO_2e/tJ) x 1

$COEF_{f,y}$ = 2011.27 tCO_2e/Mcum

Leakage emissions

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:[34]

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:

$$LE_y = LE_{CH4,y} + LE_{LNG,CO2,y} \tag{5}$$

where:

LE_y Leakage emissions during the year y in tCO_2e

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

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

Fugitive methane emissions

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

$$LE_{CH4,y} = \left\lfloor FC_y.NCV_y.EF_{NG,upstream,CH4} - EG_{PJ,y}.EF_{BL,upstream,CH4} \right\rfloor .GWP_{CH4} \tag{6}$$

where:

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

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

FC_y Quantity of natural gas combusted in the project plant during the year y in m^3

$NCV_{NG,y}$ Average net calorific value of the natural gas combusted during the year y in GJ/m^3

$EF_{NG,upstream,CH4}$ 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 Southern 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

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.coal.nic.in/welcome.html). Further, Singareni Collieries Company Limited (SCCL) is the main source for supply of coal to the southern region (http://www.coal.nic.in/cpddoc.htm) and more than 80% of coal at SCCL is mined from open cast mines (http://www.coal.nic.in/cpdanx.htm#Annexure-II). Hence 0.8 tCH4/kt coal value is used for surface mining

Sl. No	Parameter	Default Value	Remarks
2	Emission factor for fugitive CH4 upstream emissions for Oil	4.1 tCH4/PJ	As per the Table 2 of the methodology. This value includes for oil production, transport, refining and storage.
3	Emission factor for fugitive CH4 upstream emissions for Natural Gas	160 tCH4/PJ	As per the Table 2 of the methodology 296 tCH4/PJ is applicable for rest of the world and 160 tCH4/PJ is for USA and Canada. However, the US/Canada value is used as the system element (gas production and/or processing/ transmission / distribution) is predominantly of recent vintage and built and operated to international standards. Reliance Gas Transportation Infrastructure Ltd. (RGTIL) is maintaining all its processing plants and gas transmission lines matching the international standards and are of recent vintage. RGTIL conducts the regular safety audits to maintain the international safety standards with some reputed international firms
4	Oxidation factor of natural gas	1.0	IPCC value as per 2006 IPCC guidelines for National Green House Gas inventories

Leakage calculations are provided in Appendix 2.

Upstream fugitive emissions occurring in the absence of the project activity electricity generation has been calculated using the Build Margin power plants. Therefore in line with the AM0029 requirement of *ex-post* determination of the Build Margin, the Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation (tCH_4 /MWh) will also be determined *ex-post*.

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

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

1.Data / Parameter:	$EF_{BM,y}$
Data unit:	tCO_2e/MWh
Description:	Build Margin Emission Factor of Southern Regional Electricity Grid
Source of data used:	"CO_2 Baseline Database for Indian Power Sector" Version 5.0 dated 1st November 2009 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:	0.818
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 the emission factor for an electricity system".
Any comment:	-

2. Data / Parameter:	$EF_{OM,y}$
Data unit:	tCO_2e/MWh
Description:	Operating Margin Emission Factor of Southern Regional Electricity Grid
Source of data used:	"CO_2 Baseline Database for Indian Power Sector" Version 5.0 dated 1st November, 2009 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:	2006 – 07: 0.999 2007 – 08: 0.991 2008 – 09: 0.973
Justification of the choice of data or description of measurement methods and procedures actually applied :	Operating Margin Emission Factor has been calculated by the Central Electricity Authority using the simple OM approach in accordance with "Tool to calculate the emission factor for an electricity system".
Any comment:	-

3. Data / Parameter:	**Carbon Emission Factor of Natural Gas ($EF_{CO2,f,y}$)**
Data unit:	tCO_2/GJ
Description:	The CO_2 emission factor per unit of energy of natural gas in year 'y'
Source of data used:	IPCC default value has been applied (Source: Chapter-2 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	56.1 tCO_2/TJ (= 0.0561 tCO_2/GJ)
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:	-

4. Data / Parameter:	**Oxidation Factor of Natural Gas ($OXID_f$)**
Data unit:	-
Description:	Oxidation factor of natural gas
Source of data used:	IPCC default value has been applied (Source: Chapter-2 IPCC 2006 Guidelines for National Greenhouse Gas Inventories)
Value applied:	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:	-

5. 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 Authority guidelines
Value applied:	1850
Justification of the choice of data or description of measurement methods and procedures actually applied :	-
Any comment:	-

6. Data / Parameter:	**Carbon Emission Factor of Coal, Lignite, Diesel, Oil, Natural Gas**
Data unit:	tCO_2/TJ
Description:	Emission factor of Coal, Lignite, Diesel, Oil, Natural Gas. This data will be used as an input for calculating the fugitive CH4 emissions occurring in the absence of the project activity
Source of data used:	Carbon Emission Factor for Coal, Lignite & Oil: Table 2.3 - India specific CO2 emission coefficients, India's first National Communication to the United Nations Carbon Emission Factor for Diesel & Natural Gas: Table 1.4, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 1, Volume 2, Energy
Value applied:	Refer Appendix 2
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:	-

7. Data / Parameter:	**Oxidation Factor of Coal, Lignite, Diesel, Oil, Natural Gas**
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 CH4 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:	Refer Appendix 2
Justification of the choice of data or description of measurement methods and procedures actually applied :	Only IPCC default values are available.
Any comment:	-

8. Data / Parameter:	**Calorific values of Coal, Lignite, Diesel, Oil and Natural Gas 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:	NCV of Coal – Table 6.3, CEA General Review 2006 NCV of Natural Gas, Diesel : CEA Data on Petroleum fuels used by various Gas Turbines and Diesel Engine Power Plants in India in 2003-04
Value applied:	Refer Appendix 2
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority, Government of India mandated to publish information on performance of power sector in India by the Electricity Act 2003.
Any comment:	-

9. Data / Parameter:	η_{BL} ***– Efficiency of lignite fired power generating stations***
Data unit:	-
Description:	Energy efficiency of lignite fired power plant which has been identified as the baseline scenario
Source of data used:	Calculated value based on fuel consumption, NCV of lignite and electricity generation data of lignite fired power stations published in the CEA carbon-di-oxide emission database, version - 05
Value applied:	30.53%
Justification of the choice of data or description of measurement methods and procedures actually applied :	Central Electricity Authority, Government of India mandated to publish information on performance of power sector in India by the Electricity Act 2003.
Any comment:	-

10. Data / Parameter:	**Fuel consumption in lignite fired power plants in the southern region**
Data unit:	Million tonnes (MT)
Description:	This data is used as an input for calculating the Energy efficiency of lignite fired power plants
Source of data used:	CEA CO_2 Baseline database, version - 05
Value applied:	(see table below)
Justification of the choice of data or description of measurement methods and procedures actually applied :	CEA CO_2 Baseline database, version - 05
Any comment:	-

Lignite Station	**Fuel Consumption**
	Million Tonnes
NEYVELI FST EXT	1565.2
NEYVELI FST EXT	1562.0
NEYVELI TPS(Z)	1770.0

<table>
<tr><td>11. Data / Parameter:</td><td>Electricity Generation from lignite fired power plants in the Southern 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</td></tr>
<tr><td>Source of data used:</td><td>CEA CO_2 baseline database, version -05</td></tr>
<tr><td>Value applied:</td><td><table><tr><th>Lignite Station</th><th>Gross Generation</th></tr><tr><td></td><td>GWh</td></tr><tr><td>NEYVELI FST EXT</td><td>1,431</td></tr><tr><td>NEYVELI FST EXT</td><td>1,428</td></tr><tr><td>NEYVELI TPS(Z)</td><td>1,642</td></tr></table></td></tr>
<tr><td>Justification of the choice of data or description of measurement methods and procedures actually applied :</td><td>Central Electricity Authority, 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 -05 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>

12. Data / Parameter:	**CO2 emissions from Build Margin Power plants in the southern 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, version 5,0
Value applied:	Refer Appendix 2
Justification of the choice of data or description of measurement methods and procedures actually applied :	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 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

= (366 MW x 80% (PLF) x 8,760 (hours))*0.97

= 2,487,980 MWh

$EF_{BL,CO2,y}$ = 0.818 tCO_2e / MWh. (refer section B.6.1)

Baseline Emissions = 2,487,980 MWh x 0.818 tCO2e/MWh = 2,035,168 tCO2e

Project Emissions (PEy):

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

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

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

= 2,564,928 (MWh) x 1850 (MCal/MWh) / 8563(MCal/1000SCM)

= 554.14(Mcum)

$COEF_{f,y}$ = 2011.27 tCO_2e/Mcum (refer section B.6.1)

Project Emissions = 554.14(Mcum) x 2011.27 (tCO_2e/Mcum) = **1,114,531 tCO_2e**

Leakage Emissions (LEy)

Leakage: LEy = 33,764 **tCO_2e** (Please refer Appendix 2 for details of Leakage calculations)

Emission Reductions = 2,035,168 tCO_2e – 1,114,531 tCO_2e – 33,764 tCO_2e

= 886,873 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 (tCO_2e)	Estimation of baseline emissions (tCO_2e)	Estimation of leakage (tCO_2e)	Estimation of overall emission reductions (tCO_2e)
2010 –2011	1,114 ,531	2,035,168	33,764	886,873
2011 –2012	1,114 ,531	2,035,168	33,764	886,873
2012 –2013	1,114 ,531	2,035,168	33,764	886,873
2013 –2014	1,114 ,531	2,035,168	33,764	886,873
2014 –2015	1,114 ,531	2,035,168	33,764	886,873
2015 –2016	1,114 ,531	2,035,168	33,764	886,873
2016 –2017	1,114 ,531	2,035,168	33,764	886,873
2017 –2018	1,114 ,531	2,035,168	33,764	886,873
2018 –2019	1,114 ,531	2,035,168	33,764	886,873
2019 –2020	1,114 ,531	2,035,168	33,764	886,873
Total	**11,145,310**	**20,351,680**	**337,640**	**8,868,730**

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

>> **Approved monitoring methodology AM0029 "Grid Connected Electricity Generation Plants using Non-Renewable and Less GHG Intensive Fuel".**

Reference: Available on http://cdm.unfccc.int, Version 03.0 EB 39.

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:	sm^3 (million scum)
Description:	Total volume of natural gas combusted in the project plant in year y
Source of data to be used:	Fuel supplier (RIL) data
Value of data applied for the purpose of calculating expected emission reductions in section B.5	554.14
Description of measurement methods and procedures to be applied:	The value will be taken from invoices received from RIL. Fuel flow meter shall be installed at plant site and readings shall be recorded daily. The values will be correlated with invoices received from RIL. The mode of archiving data will be electronic and paper.
QA/QC procedures to be applied:	The meters will be calibrated as per the standard procedures and documents for the same will be maintained throughout. Refer Annex 4 more details.
Any comment:	100% of data will be monitored.

2. Data / Parameter:	**$NCV_{f,y}$**
Data unit:	kCal/scum
Description:	The net calorific value (energy content) per volume unit of natural gas 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	8563
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 LKPPL for verification
QA/QC procedures to be applied:	LKPPL will be cross-verifying the NCV using their own gas chromatograph readings every fortnight. Refer Annex 4 for further QA/QC procedures.
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

Source of data to be used:	IPCC 2006 default values for Carbon Emission Factor
Value of data applied for the purpose of calculating expected emission reductions in section B.6	0.0561
Description of measurement methods and procedures to be applied:	Default values for Carbon Emission Factor of Natural Gas as per Table 1.3 2006 IPCC Guidelines for National Greenhouse Gas Inventories, (Chapter 1, Volume 2, Energy) 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.
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:	From the electronic meters installed at the grid inter-connection point at the project site.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	2,487,980 MWh (Based on a normative PLF of 80 % and auxiliary power consumption of 3%)
Description of measurement methods and procedures to be applied:	As per actual meter readings taken jointly by LKPPL and PGCIL. The daily reading will be archived electronically. Monthly joint meter reading will be archived in paper form.
QA/QC procedures to be applied:	The meters will be calibrated as per the standard procedures and documents for the same will be maintained throughout. The accuracy of energy meter is 0.2 class. Refer Annex 4 for more details.
Any comment:	PLF and auxiliary consumption values based on guidelines of Central Electricity Regulatory Commission (http://cercind.gov.in)

6. Data / Parameter:	**$EF_{BM,y}$**
Data unit:	tCO_2/MWh
Description:	Build Margin Emission factor for Southern 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 5.0 dated 01 November 2009 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	0.818
Description of measurement methods and procedures to be applied:	Build Margin Emission Factor will be taken from the CO_2 baseline database published by CEA. In case the CEA database is not updated, the project proponent will calculate the Build Margin number using the available 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/MWh
Description:	Emission factor for upstream fugitive methane emissions occurring in the absence of the project activity electricity generation
Source of data to be used:	CEA CO_2 baseline database or calculated value based on available CEA data in case the database is not updated
Value of data applied for the purpose of calculating expected emission reductions in	**13.26** tCO_2 e /MWh (Refer Appendix 2 of this document for calculations)

section B.6	
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.
QA/QC procedures to be applied:	No additional QA/QC procedures are planned.
Any comment:	-

8.Data / Parameter:	PE_y
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 calculating expected emission reductions in section B.6	1,114,531
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:	-

B.7.2 Description of the monitoring plan:

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

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

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

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

LKPPL is committed to contribute a minimum of 2% of the CDM revenue realized from the sale of CERs towards sustainable development. The expected CER revenue generation from the project and the annual revenue committed towards sustainable development are summarized in the table below:

Year	Estimation of overall emission reductions (tCO2e)	CER Revenue (Million INR)[35]	Contribution to Sustainable Development (2% of CER revenue) (Million INR)
2010 –2011	886,873	691.761	13.835
2011 –2012	886,873	691.761	13.835
2012 –2013	886,873	691.761	13.835
2013 –2014	886,873	691.761	13.835
2014 –2015	886,873	691.761	13.835
2015 –2016	886,873	691.761	13.835
2016 –2017	886,873	691.761	13.835
2017 –2018	886,873	691.761	13.835
2018 –2019	886,873	691.761	13.835
2019 –2020	886,873	691.761	13.835
Total	8,868,730	6917.609	138.352

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 20/01/2010.

Lanco Kondapalli Power Pvt. Ltd. (The project proponent) has completed the application of the baseline study and monitoring methodology. The contact details appear in Annex 1 of this document.

[35] CER revenue at 12 euro and euro @ 65 INR

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: 30/01/2008

The start date of the project is based on the date of execution of the Engineering; Procurement & Construction agreement.[36]

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

>> 20 years 0 months.

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

C.2.1. Renewable crediting period

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

>> Not applicable.

C.2.1.2. Length of the first crediting period:

>> Not applicable.

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>> The 1st year of crediting will start from the date of registration of this project activity or **01/10/2010** which ever 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:

>> The proposed project is 366 MW natural gas based power plant. The Environmental Impact Assessment study for the proposed project activity was carried out by M/s Pioneer Consultants Pvt. Ltd., Hyderabad to assess the likely environmental impact and suggest mitigation measures.

The project has received the Environmental Clearance from MoEF and Consent for Establishment from Andhra Pradesh Pollution Control Board (APPCB).

[36] Evidence to be shared with DOE during the validation site visit

Environmental Impact Statement: The impact statement focuses on the study area of 10km radius around the project site. The environmental components discussed are air, noise, water, land and socio – economic environment. For each of these components, the impacts were identified, predicted and evaluated through Battelle Environmental Evaluation System. The summary of findings of this EIA study as related to the construction of CCPP is presented below:

Air:

The meteorological data such as wind direction, wind speed, maximum temperature, minimum temperature and relative humidity are collected and confirmed that it is consistent with the regional meteorology. Vegetation and human settlement in the vicinity is not likely to be affected. The existing greenbelt will further attenuate air, water or noise emissions that arise due to the power project.

Water:

The entire water requirement for the project will be met from Krishna River. A dedicated pipeline has already been laid from Old Ibrahimpatnam to the project site to meet the water requirement for the project. Waste water will be treated in the ETP. Most quantity of the treated effluent will be used for green belt within the plant premises to the extent possible and the remaining will be discharged into the Budameru drain after ensuring compliance with APPCB standards.

Noise:

The impact of noise generated by the project on the community will be insignificant. It is observed that the general noise level in the plant premises would be within the limits. However, average noise level may increase due to operation of gas turbines, steam turbines and compressors. The increase in the noise levels due to this activity will be limited to the plant premises only.

Land:

There is absolutely no adverse impact on land environment due to the project. There are no important plant species that are rare and endangered or threatened either at plant site or in adjoining areas. The water requirement for green belt development will be met from treated effluents. The soil chemistry will not be affected much.

Socio-economic environment:

The impact of the project will be more on the positive side than on the negative side. These positive impacts can be attributed to development of area with increase in job opportunities, health status, educational status, economic output and other social benefits. There will be a manifold increase in the employment opportunities.

The EIA resulted in the preparation of an Environmental Management Plan (EMP) for the project activity. EMP for the power plant has been designed for efficient functioning of the plant so as to minimize the adverse environmental effects. The EMP recommends measures for impact minimization during both the construction and operations phase of the project.

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

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

SECTION E. Stakeholders' comments

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

>> The local stakeholders of the project activity were invited through an invitation letter dated 22nd December, 2008. The date and venue of the local stakeholders' consultation meeting was explicitly stated in the invitation letter. The stakeholders identified for the project activity are

- Representative from the Local Pollution Control Board
- Representative from the adjacent village
- Representative from Gas Authority of India Limited
- Contractor
- Government official
- Employees of LKPPL

The local stakeholders' consultation meeting to discuss stakeholder concerns was held on 6th January, 2009. Representative from LKPPL delivered the welcome speech wherein the basic purpose of convening such meeting was explained. It was also elaborated how the project activity leads to reduction in carbon-di-oxide emission in the atmosphere. Subsequently a questionnaire was circulated amongst the stakeholders who were present during the discussion. All the related document would be shared with DOE during the validation process.

E.2. Summary of the comments received:

>> The summary of the comments received during the meeting is as follows:

The stakeholders opined that the project activity is beneficial to the local people in many ways. The project activity provides employment opportunities to the local population. Since the project uses efficient equipment powered by latest technology, there would be reduction in specific consumption of Natural Gas, which would lead to reduction in emission of greenhouse gases. Also, they pointed out that electricity generation through usage of less carbon intensive fuels is environmentally friendly.

The local population mentioned that the setup of the project improved drinking water and street lighting facilities in the village. They hoped that setup of the project would encourage development of other small scale industries in the village. Most of the stakeholders mentioned that the project has a positive impact on the environment as it emits less greenhouse gases. They also encouraged the green belt developed around the project activity by the project proponent. The minutes of the meeting would be shared with DOE during the validation process.

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

>> The stakeholders held a positive opinion about the project, and no negative comments were received. Therefore, there was no requirement of addressing the negative comments during the meeting.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Lanco Kondapalli Power Private Limited
Street/P.O.Box:	Lanco House, Plot No. 4, Software Units Layout,
Building:	HITEC City, Madhapur
City:	Hyderabad
State/Region:	Andhra Pradesh
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Telephone:	+91 40 4009 0400
FAX:	+91 40 2311 6127
E-Mail:	lkpl@lancogroup.com
URL:	www.lancogroup.com
Represented by:	
Title:	Director & CEO
Salutation:	Mr.
Last name:	Rao
Middle name:	Panduranga
First name:	P
Department:	Lanco Kondapalli Power Private Limited
Mobile:	+91-986-662-9520
Direct FAX:	+91 40 2311 8444
Direct tel:	+91 40 4009 0400
Personal e-mail:	ppr@lancogroup.com

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[37]:

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

Simple Operating Margin

	Southern Grid (tCO2e/GWh)
Simple Operating Margin - 2006-07	999.12
Simple Operating Margin - 2007-08	990.62
Simple Operating Margin - 2008-09	972.92
Average Operating Margin of last three years	987.56

Build Margin

	Southern Grid (tCO2e/GWh)
Build Margin	817.92

Combined Margin Calculations

	Southern Grid (tCO2e/GWh)
Combined Margin	895.42

[37] http://www.cea.nic.in/planning/c%20and%20e/Government%20of%20India%20website.htm

CALCULATION OF ENERGY EFFICIENCY OF BASELINE ALTERNATIVE [38]

Lignite Station	Fuel Consumption	NCV	Input Energy	Generation	Output Energy	Efficiency
	Million Tonnes	kCal/kg	GJ	GWh	GJ	
NEYVELI FST EXT	1565.2	2,588	16,955,219	1,431	5,150,336	30.38%
NEYVELI FST EXT	1562.0	2,588	16,920,866	1,428	5,139,901	30.38%
NEYVELI TPS(Z)	1770.0	2,588	19,173,407	1,642	5,910,512	30.83%
Efficiency of Lignite Based Power plant						**30.53%**
Carbon - di -oxide emission coefficient	106.15	tCO_2/TJ				
	0.10615	tCO_2/GJ				
Emission factor for baseline option	1.25	tCO_2/MWh				

Conversion factor used: 1kWh = 3.6 MJ

[38] Reference : http://cea.nic.in

Annex 4

MONITORING INFORMATION

Monitoring Plan for CDM activity:

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

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

$$ER_y = BE_y - PE_y - LE_y$$

The parameters that would be monitored for PE_y are:

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

The parameters that would be monitored for BE_y are:

3. **Net Electricity Generation (EG_y):** Based on daily meter readings of the gross electricity generated and the auxiliary consumption.

Net Electricity Generated	=	Electricity Supplied by GTG – 1	+	Electricity Supplied by STG – 1	-	Auxiliary Consumption of GTG – 1& STG – 1.

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

I. Monitoring for Net Electricity Generation (EG_y):

Metering Plan

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

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

Metering equipments shall be electronic meters. The Gross electricity generation measurements from Gas Turbine Generator and Steam Turbine Generator are recorded using respective main meters and check meters. Sum of Gross generation from the Gas Turbine Generator and the Steam Turbine Generator shall be the gross generation from the plant.

3. Auxiliary Consumption

Auxiliary consumption for the power station is met by import of electricity through the station transformer.

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

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

All the related energy meters used for recording gross electricity generation and auxiliary power consumption will be calibrated as per the norms and regulation maintained at PGCIL

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

Metering Plan

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

1. Main meter - Located at Gas conditioning skid
2. Check meter - Located at the inlet of Gas Turbine

The meter readings are displayed in the plant DCS and is recorded from the DCS manually on daily basis (0.00 Hrs every day) in electronic format and are archived monthly in electronic format. The meter readings are archived in paper form.

Metering Equipment for Natural Gas Consumption:

Metering equipments for natural gas consumption consists of ultrasonic meters along with differential pressure transmitters, pressure transmitters and TT for temperature measurements. The Natural Gas Consumption metering is done using a main meter and a check meter. The main meter is located at the supplier gas conditioning/metering skid and the check meter is located at the inlet of the gas turbine. The main meter is installed and owned by the Gas Supplier and check meter is installed and owned by the Project proponent. The metering equipment shall be maintained in accordance with OEM guidelines as per relevant standards.

The measurement shall include all corrections in installations practices recommended for accurate metering of gas by the 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 as well as project proponent. The metering equipment shall be maintained in accordance with OEM guidelines as per

relevant standards. The measurements are obtained daily by Gas Supplier and are transmitted to Project Proponent every fortnight.

Meter Test Checking for Natural Gas Meter Reading (Natural Gas Consumed): The natural gas meter shall be tested at site for accuracy periodically against an accepted laboratory standard meter in accordance with prescribed standards. The consumption registered by the meter will hold well as long as the error in the meters is within the permissible limits.

If on calibration, the Gas Supplier's meter registers a variation of more than + 2 (two) percent or if the Gas Supplier's meter is out of service, the procedure for the quantity of Gas during the period between the last calibration and the present shall be followed as per the provisions of GSA:

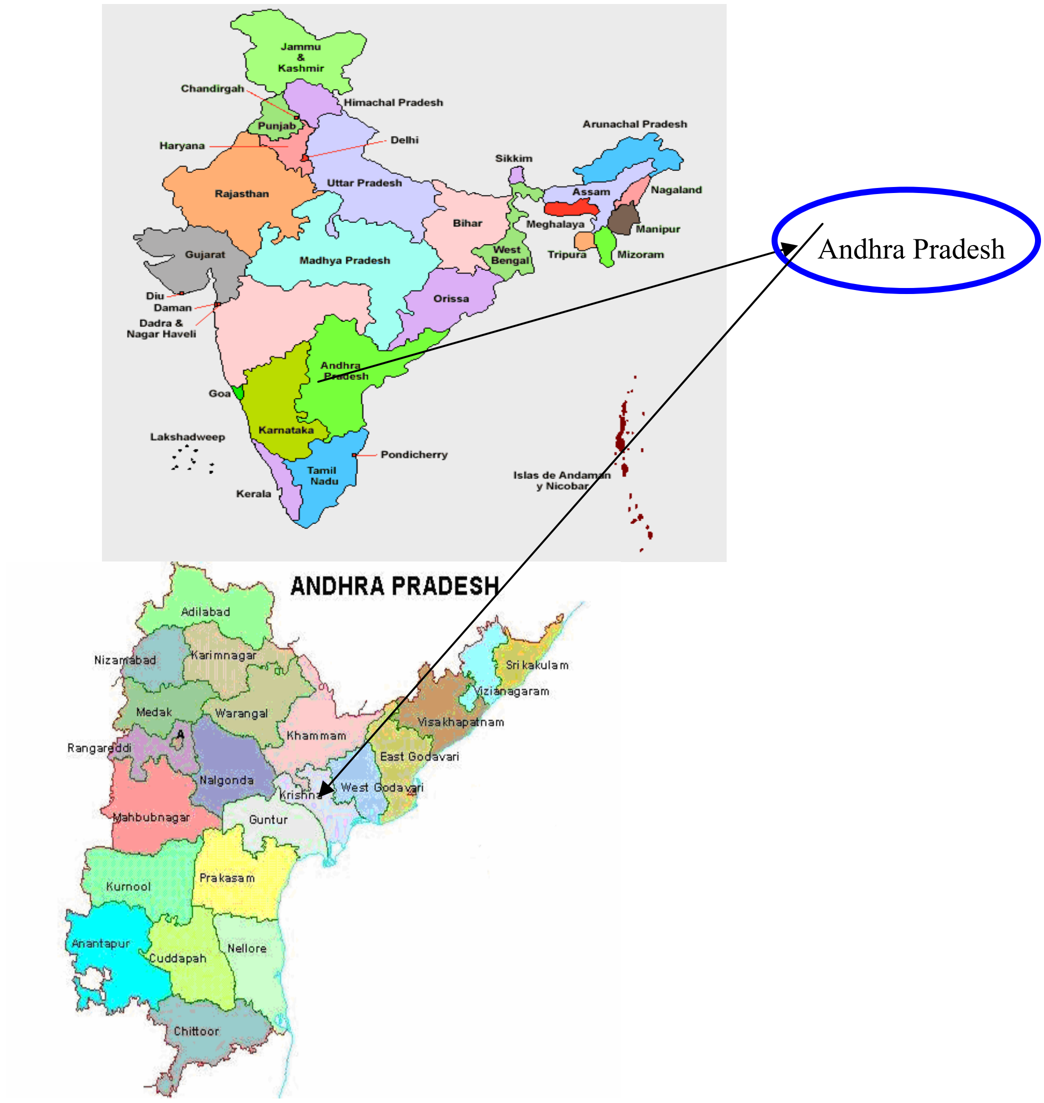
I. By using recording by the meter of the Project Proponent and accurately registering: or

II. By correcting the error if the percentage of error is ascertainable by calibration, test or mathematical calculation: or

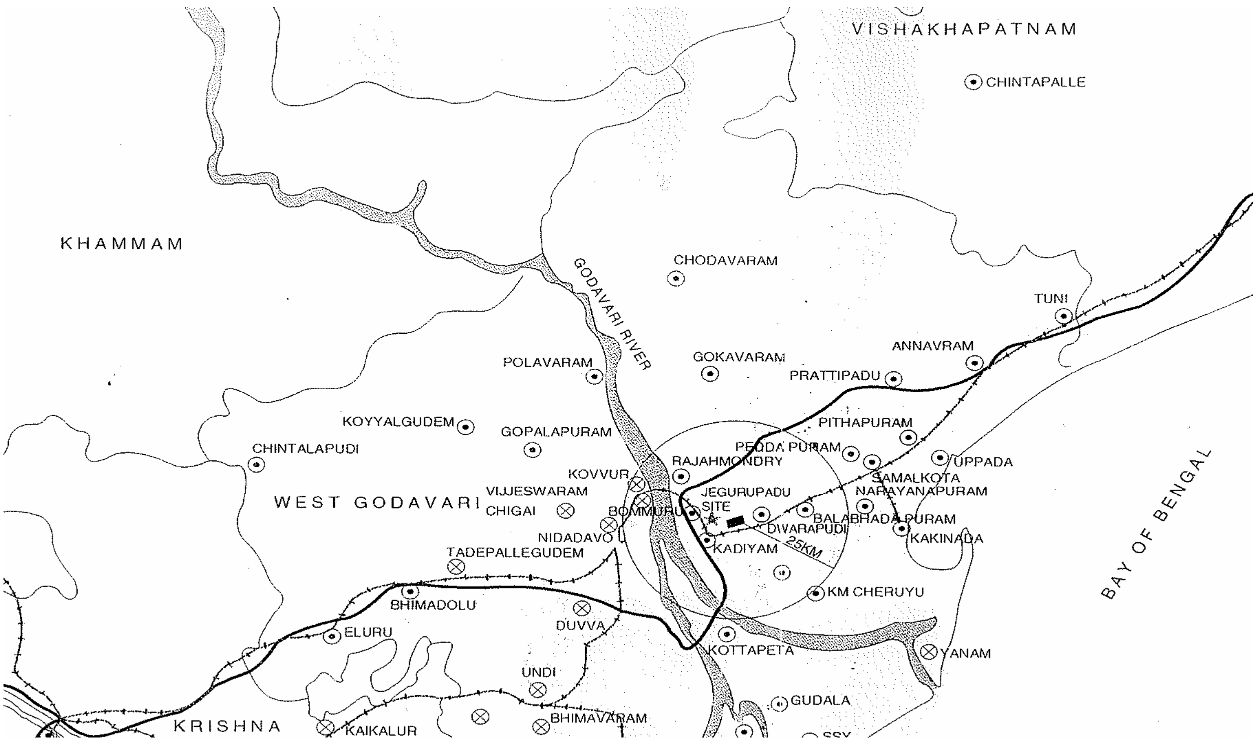
III. By estimating the volume of Gas delivered by comparison with deliveries during the period under similar conditions when the Gas supplier's meter was registering accurately.

Appendix 1

Project Location Map




Khammam
Nalgonda
Huzurnagar
Tiruvuru
Makkapeta
Jaggayyapeta
Nandigama
Penuganchiprolu
Janardanavaram
Vissannapeta
Kambhampadu
Ramanakkpeta
KRISHNA
West Godavari
Mailavaram
Nuzvid
Raghavapuram
Chandralapadu
Gollapalle
Konduru
Kondapalle
Pedda Avutapalle
Agiripalle
Guntur
Gannavaram
Telaprolu
Kolleru
Kaikalur
Mandavalli
Kankipadu
Gudivada
Mudinepalle
Pallepalem
Vuyyuru
Bantumilli
Kavutaram
Pamarru
Pedana
Nidumolu
Gilduru
Bandar Fort
MACHILIPATNAM
Challapalle
Avanigadda
Koduru
Nagayalanka
Talagadadivi
Bay
of
Bengal
Prakasam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CHINTAPALLE
KHAMMAM
GODAVARI RIVER
CHODAVARAM
TUNI
ANNAVRAM
POLAVARAM
GOKAVARAM
PRATTIPADU
KOYYALGUDEM
GOPALAPURAM
PITHAPURAM
CHINTALAPUDI
PEDDA PURAM
UPPADA
RAJAHMONDRY
KOVVUR
SAMALKOTA
NARAYANAPURAM
VIJJESWARAM
JEGURUPADU
WEST GODAVARI
CHIGAI
BOMMURU
SITE
BALABHADRAPURAM
DWARAPUDI
KAKINADA
NIDADAVOLU
KADIYAM
25KM
BAY OF BENGAL
TADEPALLEGUDEM
KM CHERUYU
BHIMADOLU
DUVVA
ELURU
KOTTAPETA
YANAM
UNDI
GUDALA
KRISHNA
KAIKALUR
BHIMAVARAM

Appendix 2

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 m^3

$NCV_{NG,y}$ Average net calorific value of the natural gas combusted during the year *y* in GJ/m^3

$EF_{NG,upstream,CH4}$ 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

In the present context only NG will be used as fuel. Hence leakage 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 ignored.

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

Sr. No	Fugitive Emissions due to gas usage	Unit of measurement	Formula for calculation	Value
1	Fugitive CH4 emission factor	tCH4/PJ		160.00
2	Annual Gas consumption (based on 50% NG of the total NG consumption)	Mcum		554.14
3	Calorific Value	kCal/SCM		8,563
4	Calorific Value	TJ/Mcum	= (3) x 4.1868/10^3	35.85
5	Energy content in Gas consumed	PJ	= (2) x (4)/10^3	19.87
6	Fugitive CH4 emissions	tCH4	= (1) x (5)	3,178.70
7	Equivalent CO2 emissions	tCO2e	= (6) x 21	**66753**

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

There is no LNG consumption in the proposed CDM project activity.

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 $EF_{BL,upstream,CH4}$

Fugitive emission factor	tCO2e/GWh	13.26
Electricity generations from the Project activity	GWh	2,487.98
Fugitive Emissions in the absence of project activity	tCO2e	**32,988**

Leakage = 66,753tCO2e – 32,988 tCO2e = 33,764 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	17,290,548	1,431	12,083		0.8		202,998
Lignite	5,632,280	1,150	4,897		0.8		82,274
Diesel	428,111	3,093		6		4.1	498
Natural gas	2,220,410	1,860		40		160	132,987
Oil	279,988	3,108		4		4.1	312
Total							419,068

Net electricity generation (Million kWh) corresponding to build margin from CEA Database	31,606

Fugitive emission factor (tCO2e/Million kWh)	**13.26**

Selection of Thermal Plants in Southern grid that are included in the build margin

NAME	UNIT_NO	DT_COMM	CAPACITY MW AS ON 31/03/2009	STATE	FUEL 1	FUEL 2	2008-09 Absolute Emissions t CO2	2008-09 Net Generation GWh
RAYAL SEEMA	3	25-Jan-07	210	ANDHRA PRADESH	COAL	OIL	1,496,473	1,577
RAYAL SEEMA	4	20-Nov-07	210	ANDHRA PRADESH	COAL	OIL	1,449,026	1,527
R_GUNDEM STPS	7	26-Sep-04	500	ANDHRA PRADESH	COAL	OIL	3,683,860	3,919
SIMHADRI	1	22-Feb-02	500	ANDHRA PRADESH	COAL	OIL	3,641,001	3,865
SIMHADRI	2	24-Aug-02	500	ANDHRA PRADESH	COAL	OIL	3,970,468	4,215
RAICHUR	7	11-Dec-02	210	KARNATAKA	COAL	OIL	1,595,471	1,540
BELLARY TPS	1	3-Dec-07	500	KARNATAKA	COAL	OIL	1,454,248	1,106
Total Coal							**17,290,548**	**17,750**
LVS POWER DG	1	18-Oct-01	18.4	ANDHRA PRADESH	DISL	n/a	0	0
LVS POWER DG	2	18-Oct-01	18.4	ANDHRA PRADESH	DISL	n/a	0	0
SAMAYA	1	22-Sep-01	106	TAMIL NADU	DISL	OIL	428,111	663

NALLUR DG								
Total DG							**428,111**	**663**
PEDDAPURAM CCGT	1	8-Nov-02	220	ANDHRA PRADESH	GAS	NAPT	465,963	979
TANIR BAVI	1	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	2	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	3	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	4	8-Jun-01	42.5	KARNATAKA	GAS	NAPT	82,409	150
TANIR BAVI	5	21-Nov-01	50	KARNATAKA	GAS	NAPT	96,951	177
VALUTHUR GT	1	24-Feb-02	58.9	TAMIL NADU	GAS	n/a	108,174	262
VALUTHUR GT	2	13-Mar-03	35.1	TAMIL NADU	GAS	n/a	64,464	156
VALUTHUR GT	3	1-Sep-08	58.5	TAMIL NADU	GAS	n/a	62,109	150
VALUTHUR GT	4	1-Sep-08	33.7	TAMIL NADU	GAS	n/a	35,779	87
VALUTHUR GT	5	6-May-08	59.8	TAMIL NADU	GAS	n/a	98,995	240
KUTTALAM GT	1	27-Nov-03	64	TAMIL NADU	GAS	n/a	170,074	432
KUTTALAM GT	2	24-Mar-04	37	TAMIL NADU	GAS	n/a	98,324	250
KOVILKALAPPAL	1	14-Jul-01	107	TAMIL NADU	GAS	n/a	275,812	666
VALANTHARVI GT	1	29-Oct-05	52.8	TAMIL NADU	GAS	n/a	125,766	263
VALANTHARVI GT	2	15-Apr-06	14.8	TAMIL NADU	GAS	n/a	35,253	74
VEMAGIRI CCCP	1	13-Jan-06	251.5	ANDHRA PRADESH	GAS	n/a	163,855	424
VEMAGIRI CCCP	2	8-Jun-06	137	ANDHRA PRADESH	GAS	n/a	89,257	231
Total Gas							**2,220,410**	**4,991**
NEYVELI FST EXT	1	21-Oct-02	210	TAMIL NADU	LIGN	OIL	1,800,140	1,431
NEYVELI FST EXT	2	22-Jul-03	210	TAMIL NADU	LIGN	OIL	1,796,493	1,428
NEYVELI TPS(Z)	1	11-Oct-02	250	TAMIL NADU	LIGN	OIL	2,035,646	1,642
Total Lignite							**5,632,280**	**4,500**
BELGAUM DG	1	31-Mar-01	27.1	KARNATAKA	OIL	n/a	93,329	141
BELGAUM DG	2	31-Mar-01	27.1	KARNATAKA	OIL	n/a	93,329	141
BELGAU	3	31-Mar-	27.1	KARNATAKA	OIL	n/a	93,329	141

M DG	01		
Total oil		**279,988**	**424**

Source: CEA Database Version 5.0

Type of FUEL	**Net Calorific Value (TJ/ 103 tonnes or TJ/Mcum)** (Note)	**Carbon Emission Factor (tC/ TJ)**	**Fraction of Carbon Oxidised Oxidation Factor**	**Emission Factor (tCO_2/ 103 tonnes or tCO_2/Mcum)**
Coal	14.94	26.13	1.00	1,431
Diesel	41.76	20.20	1.00	3,093
Lignite	10.83	28.95	1.00	1,150
Natural Gas	33.16	15.30	1.00	1,860
Oil	40.17	21.10	1.00	3,108

Note: The NCV has been calculated by multiplying the GCV with the ratio of NCV to GCV.