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

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SECTION A. General description of project activity

A.1 Title of the project activity:

>> 119.8 MW Natural Gas based Combined Cycle Power Plant, at Tanjavur, Tamilnadu by M/s Aban Power Company Limited
Version 02
16/12/2006

A.2. Description of the project activity:

>>

Purpose

The purpose of the project activity is to set up a 119.8 MW Natural Gas based Combined Cycle Power Plant (CCPP) and export power to the Tamilnadu state power grid. This power plant operating on cleaner fuel like Natural Gas will lead to lower Carbon Dioxide (GHG) emissions for producing equivalent amount of power as compared to the other power plants in the region operating on other fuels like coal/ lignite/oil/ naphtha.

The project increased the installed electricity generating capacity of Tamilnadu State Electricity Board (TNEB), thereby helping in bridging the gap between demand and supply of electrical energy in the state. The project will also enhance the economic growth and development of the area.

The Natural Gas (about 5,00,000 Sm^3 per day) for the power generation is supplied at the plant boundary, through a dedicated pipeline, by GAIL (India) Limited, from a gas station of Oil and Natural Gas Commission (ONGC) located at Kuttalam, which is about 8 km from the plant site.

Project's contribution to sustainable development

A brief description of the contribution of the project activity towards 'Sustainable Development of India' is discussed hereunder.

1. Environment Wellbeing

The project activity is a clean fuel power project, which uses Natural Gas as a fuel for power generation and export the clean power to TNEB grid. This power generation substitutes the power generation by TNEB which is predominantly operated with coal as fuel. Since the Carbon Dioxide (CO2) emission due to combustion of Natural Gas is substantially less as compared to combustion of coal, lignite or Naptha, the project helps in reducing GHG emission.

Indian economy is highly dependent on "Coal" as fuel to generate energy and for production processes. Thermal Power Plants are the major consumers of Coal in India, and yet the basic power needs of a large section of society are not being met. This results in excessive demands for electricity and places immense stress on the environment. Changing coal consumption patterns will require a multi-pronged strategy focusing on demand, reducing wastage of energy and the optimum use of Clean Energy Sources like Natural Gas.

Since this project activity is based on natural gas, it will positively contribute towards the reduction in (demand) use of coal and increasing its availability to other places where natural gas is not available.

The project activity, by feeding clean power to grid will reduce CO_2 emissions, which would have been otherwise generated by coal dominated power plants. This project activity therefore has excellent environmental benefits in terms of reduction in carbon emissions and coal resource conservation. Also, gas based power plants would not lead to production of huge quantities of solid waste (like ash in thermal power plants) and hence reduces the burden of solid waste disposal.

2. Technical wellbeing

The project activity also consumes comparatively lesser quantity of water than coal based power plants and hence conserves scarce resource and also due to the installation of air cooled condensers in place of water cooled condensers. The project also uses the latest available technology for gas based power generation using FA type of gas turbines.

3. Social wellbeing

Project activity is providing direct employment to about 60 persons and indirectly creating business opportunity for stakeholders like bankers, consultants, suppliers, manufacturers, contractors, traders, caterers etc. Also, plant management is involved in several social activities like conducting health camps, setting up of artificial limb centre etc.

4. Economic Wellbeing

Implementation of project activity would encourage the economic development in the region and also improves the economic wellbeing of neighbouring villages by providing direct and indirect employment opportunities in the region. The project implementation also improves the power supply situation in the state which in turn help industry to improve their productivity due to reduction of power cuts.

Overall, this project activity will contribute to the Environmental & Social issues locally and globally by:

- Exporting 113.2 MW to TNEB and thereby eliminating the generation of same quantity of power by a fossil fuel based power plants, which would have been installed to meet the increasing electricity supply and demand gap in the state;
- Conserving Coal, a fuel used by masses in India for daily living needs;
- Making coal available for other important applications;
- Reducing GHG (Carbon Dioxide) emissions; and

- Providing direct employment to about 60 persons and indirectly creating business opportunity for stakeholders like bankers, consultants, suppliers, manufacturers, contractors, traders, caterers etc.
- Space requirements per MW for a gas based stations are less than coal based stations.

A.3. Project participants:

>>

Name of Party involved ((host) indicates a host Party)	Private and/or public entity(ies) project participants (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
India (Host)	Aban Power Company Limited (APCL)	No

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

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A.4.1.1. Host Party(ies):

>>

India

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

>>

Tamilnadu

A.4.1.3. City/Town/Community etc:

>>

Thanjavur District

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

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The power plant has been set up in Karuppur Village, Taluk Thiruvidaimarudur of Thanjavur District in the state of Tamilnadu. The site is at 11º7’30” latitude and 79º31’30” longitude. The site elevation is 10.5 m above the mean sea level.

The nearest Railway station is at Kuttalam, which is about 8 kms from the site towards south. The power plant site including infra-structural facilities, green belt, open space etc. encompasses a total area of 51 acres. The ambient temperature varies between 20ºC to 35ºC and the annual average rainfall is about 1300 mm.

The Natural Gas (about 5,00,000 Sm^3 per day) for the power generation will be supplied at the plant boundary, through a dedicated pipeline, by GAIL (India) Limited, from a gas station of Oil and Natural Gas Commission (ONGC) located at Kuttalam, which is about 8 kms from the plant site.

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

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The project activity is a large scale potential CDM project, which fits under the Category 1: Energy industries (renewable-/ non renewable sources) as per 'List of Sectoral Scopes'.

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

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Project is a grid-connected Natural Gas based Combined Cycle Power Plant

The Natural gas based Combined Cycle Power Project (CCPP), with installed capacity of 119.8 MW, has one (1) Gas Turbine Generating (GTG) Unit of 68.6 MW rated capacity, one (1) Heat Recovery Steam Generator (HRSG) and one (1) Steam Turbine Generating (STG) Unit of 51.2 MW rated capacity, along with all electrical systems, controls and Instrumentation, Civil, Structural and Architectural works.

The 'Can' type combustor is fired with Natural gas and produces hot, high pressure, low NOx containing flue gases, which is expanded in the Gas Turbine. The Gas turbine would drive on one end an AC generator and on other end an axial compressor, which supplies the compressed ambient air to the combustor. The heat of high temperature exit gases of turbine is recovered in HRSG, , designed to maximize the heat recovery of gases and allows the outlet of gases at minimum stack temperature (105-110ºC). The steam turbine of single cylinder, no reheat, condensing type is designed to operate with steam at 105 bar, 538ºC / 6.9 bar, 257ºC. The designed speed of turbine is 5810 rpm and is suitable for continuous operation at Maximum Continuous Rating (MCR) output in the frequency band of +5% to –3% of 50 Hz without any limitation. The steam turbine has control system of electro hydraulic type. The turbine is designed for sliding pressure mode of operation for high efficiency at part load.

The cycle efficiency of natural gas based combined cycle power plant is in the range of 50-55% as compared to average cycle efficiency of 36-42% of coal fired Rankine cycle based thermal power plants[1]. The project, to be operated by independent power producer, is one of the rare CCPP projects in India, which will work at such high cycle efficiency.

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[1] Infraline report on " Natural gas in Power Sector: Issues and Challenges" – Page No. 2 (http://www.infraline.com/ong/naturalgas/enduse/InfralinePaperNatGasPowSec.pdf). This page can be viewd with paid subscription.

About 5,00,000 Sm^3 /day of Natural Gas (NG) for the power generation is supplied at the plant boundary, through a dedicated pipeline, by GAIL (India) Limited, from a gas station of Oil and Natural Gas Commission (ONGC). The gas pressure is boosted to 27 kg/cm^2(g) as required by gas turbine. The gas-conditioning unit, to be installed at plant, will comprise of knock out drum, gas filter, separator, fuel control, isolation, emergency stop, vent etc.

Other auxiliary systems like Lube Oil and Governing System, Condenser System, Feed Water System, Power Evacuation System etc. are also installed.

The Power generated from the GTG and STG units is stepped up to 110 KV by generator transformers and supplied to TNEB state grid. The NG based power plant operates at more than 85% of the capacity throughout the year. The plant is designed to operate well within the environmental norms prescribed by various statutory authorities.

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

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The estimated emission reductions for the chosen period of 10 years are 1,811,530 ton CO2e.

Years	Annual estimation of emission reductions in tones of CO_2eq
2006	181153
2007	181153
2008	181153
2009	181153
2010	181153
2011	181153
2012	181153
2013	181153
2014	181153
2015	181153
Total	**1811530**
Total no of crediting years	**10**
Annual average over the crediting period of estimated reductions (tones of CO_2 e)	**181,153**

A.4.5. Public funding of the project activity:

>> No public funding from parties included in Annex I is available to the project.

SECTION B. Application of a baseline methodology

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

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"Title: Approved baseline methodology AM0029 (Version 01, 19th May 2006) "Baseline Methodology for Grid Connected Electricity Generation Plants using Natural Gas"

This methodology also uses the build margin (BM) and operating margin (OM) approach as specified in ACM0002 "Consolidated methodology for grid-connected electricity generation from renewable sources" (Version 6) and makes reference to version 2 of the "tool for the demonstration and assessment of additionality".

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

>> The project activity meets the methodology applicability criteria as under:

- The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant.
- The geographical/ physical boundaries of the baseline grid are clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available.
- Natural gas is sufficiently available in the Tamil Nadu state region of India.
- The project opts for cleaner fuel natural gas in place of coal/lignite which is higher GHG intensive fuel, though use of coal in the Indian power generation context is financially more attractive, and that there are no state/ sectoral regulations constraining the use of higher GHG intensive fuels.

The conditions of the project are compared with the applicability conditions mentioned in the methodology as below:

Applicability condition	How applicable to the project activity
The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant	APCL's project activity is the construction and operation of a new 119.8 MW natural gas fired power plant, which is connected to the TNEB grid.
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 southern regional grid of India may be considered as the baseline grid since the TNEB grid is interlinked with other state grids in southern India through which significant quantity of energy is exchanged. The geographical boundary of the southern regional grid can be clearly identified and information for estimation of baseline emissions is publicly available in CEA publications.
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.	The GAIL (India) Limited supplies natural gas to the project activity from its Kuttalam gas field located in the Cauvery basin at a distance of 8 km from the project site. Natural gas is abundantly available in the region to meet the project demands. The project activity doesn't constrain future capacity additions in the area which is evident from the fact that other new natural gas based power plants are coming up in the region. TNEB is implementing a natural gas based project near Ramanathapuram at present with the gas availability in the region. Based on the commercial availability of the gas from the recently found new gas reserves in the region (as mentioned below), there are many more gas based projects expected to come up in the region. **Future gas availability in the country** As per the latest reports from leading research organizations in the sector (such as Infraline), there will be an upsurge in the total supply due to sizable discoveries of natural gas made by both the National Oil Companies (NOCs) and Private/Joint Venture companies. In the past two to three years, the NOCs viz. ONGC and OIL, made 18 significant discoveries of which 12 are onland and 6 offshore. Many hydrocarbon discoveries have been made by private and joint venture companies in the blocks awarded under

	NELP and Pre-NELP in the past four years in four major areas: Krishna- Godavari offshore, Gulf of Cambay, onland Rajasthan and Cambay Basins. The most significant of these discoveries are series of gas discoveries made by the consortium of Reliance Industries Ltd. (RIL) and Niko Resources Ltd. in the blocks KG-DWN-98/3 in Andhra Pradesh and NEC-OSN-97/32in Orissa. In the KG block, the in-place gas reserves are expected to be in the range of 10-14 tcf. The production capacity is projected at 40-60 MMscmd over 15-20 years from 2007-08 onwards. In the Orissa block, the initial estimates have indicated in place reserves of 4-5 tcf. This discovery will yield around 20 MMscmd of gas from 2008 onwards. Various other discoveries have been made by Cairn Energy Pvt. Ltd. in the KG basin, Gulf of Cambay and Rajasthan and by NIKO resources in the Cambay basin. The situation will further improve with increase in R-LNG supplies and beginning of natural gas imports from other countries through transnational pipelines. The R-LNG supplies are anticipated to add 40 MMscmd of gas in next three to four years to India.s total supply of gas. According to a survey carried out by Marketing and Development Research Associates for GAIL, the transnational pipelines would supply 56 MMscmd of gas by 2008-09 with 28 MMscmd of gas coming each from Iran and Myanmar. **Gas availability in Tamilnadu** The natural gas market in Tamil Nadu is procuring gas from fields located in the Cauvery basin. The Cauvery basin occupies most of the coastal plains of Tamil Nadu and Pondicherry and extends offshore into the Bay of Bengal. The southern portion of the basin extends across Park Strait and Gulf of Mannar into the western coastal area of Sri Lanka. The exploratory efforts in the basin since 1964 have resulted into discovery of 26 small and medium sized oil and gas fields establishing a total of 92.29 MMT of in-place oil and oil equivalent gas reserves. The prognosticated resources of the basin are at 610 MMT. Currently, ONGC is

	operating gas fields near the Karaikal region. Apart from these, ONGC also owns 40% of the HOEC operated PY-3 offshore field in the Cauvery basin. Tamil Nadu has around 25 gas consumers in the state. While a large majority of these consumers are small-medium industrial enterprises, the state also contains several large power consumers. The state currently does not have any gas consumption in the fertilizer, steel or distribution sectors. The allocated gas supply (1.38 MMscmd) at present in Tamilnadu is more than the requirement for the power plants (1.19 MMscmd). From the above, it is evident that gas supply will be available sufficiently to meet the demand requirements of the power sector and the project activity does not create any leakage in the state.
Natural gas should be primary fuel. Small amounts of other startup or auxiliary fuels should be used, but can comprise no more than 1% of total fuel use.	The project activity is designed for exclusive firing by Natural Gas and usage of no other fuels is envisaged 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 identified here.	Based on the information gathered on various new gas exploration projects (as mentioned above), it is very likely that sufficient gas is going to available in the country in the future which can be sufficient enough to generate more than the existing capacity of gas based power plants in the country. During the last few years, the Natural Gas (including LNG) prices have been fluctuating which in fact indicates that prices have not become inelastic (Refer **http://iis-db.stanford.edu/evnts/4582/Brown_NorthAmericaNatGas.pdf)** • On the basis of the above it can be easily concluded that there are no price-inelastic supply constraints as far as natural gas (including LNG) is concerned during the crediting period and therefore there are no significant leakages.

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

>> For the project activity, the project boundary is from the point of fuel supply to the point of power export to the grid where the project proponent has full control. Thus, the project boundary covers, gas supply and gas compression inside the plant boundary, boiler, gas and steam turbines and all other power generating equipment, captive consumption units and energy consuming equipment, since the part of the electricity generated will be used for auxiliary consumption. Since, the project would not have any impact on T&D losses it is not included in the project boundary.

A Flow chart indicating the project boundary is illustrated in the diagram below:

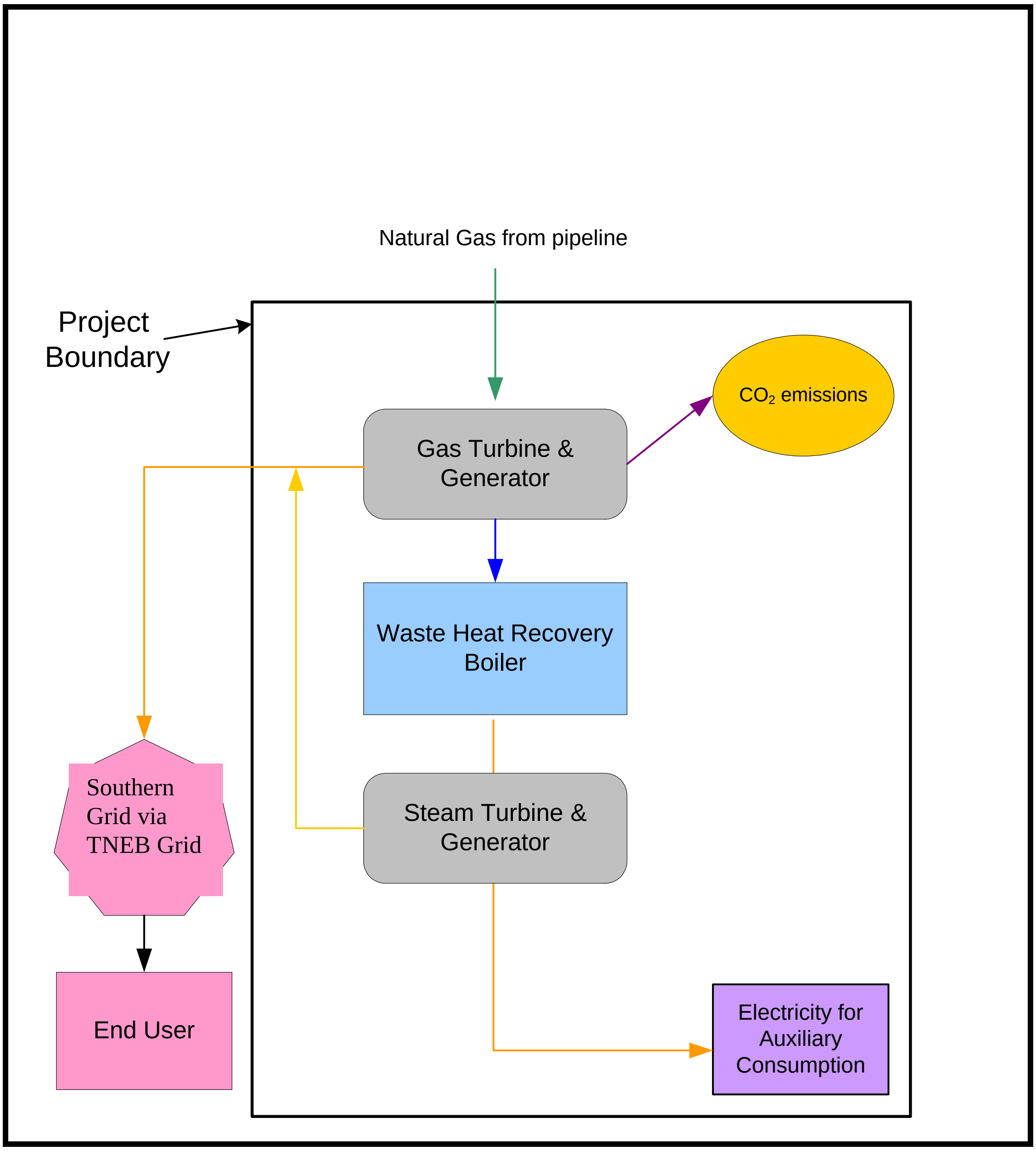

Fig 2.2: The project boundary

As mentioned above, the spatial extent of the project boundary includes the project site and all the power plants connected physically to the baseline grid as defined in ACM0002.

In the calculation of project emissions, only CO_2 emissions from fossil fuel combustion at the project plant are considered. In the 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 below table:

	Source	Gas	Included?	Justification / Explanation
Baseline	Power generation in baseline	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification. This is conservative.
		N_2O	No	Excluded for simplification. This is conservative.
Project Activity	On-site fuel combustion due to the project activity	CO_2	Yes	Main emission source
		CH_4	No	Excluded for simplification
		N_2O	No	Excluded for simplification

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

>> The methodology is based on the approach of "Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment" and needs financial data of the project activity and its alternatives. For detailed baseline analysis, above-mentioned methodology is applied as under for the evaluation of selected project as a CDM project and calculation of emission reductions as per the baseline.

The project activity increases the installed capacity of the Southern electricity grid, thereby reducing the energy and power demand shortage. Also, it further avoids / delays the capacity addition of equivalent project size and reduces the carbon intensity of the grid mix. Therefore, the project activity needs the data/information of the grid mix regarding the baseline emissions for further evaluation of project activity as a CDM project and same data/information was collected from government/non-government organisations and other authentic sources.

The following paragraphs describe in a step by step manner how the methodology is applied in the context of the project activity.

Identification of baseline scenario for the project activity:

Baseline selection guideline as mentioned in the methodology has been applied.

Step1. Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a. Define alternatives to the project activity

It is required to identify realistic and credible alternative(s) that were available to project activity of APCL or similar project developers that provide output or services comparable with the project activity. These alternatives are required to be in compliance with all applicable legal and regulatory requirements.

The following types of possible alternatives have been analysed as prescribed by the baseline methodology (AM0029):

- The project activity not implemented as a CDM project
- Power generation using natural gas, but technologies other than the project activity
- Power generation technologies using energy sources other than natural gas (that have recently been constructed or are under construction or are being planned)
- Import of electricity from connected grids, including the possibility of new interconnections

The plausible baseline scenarios among the above alternatives have been identified using the following eligibility criteria as recommended by AM0029:

- ***Realistic and credible***
  These include:
  Those alternatives for which technology is commercially established and available
  Those alternatives which are within the investment capacities of the promoters
  Those alternative technologies that are prevailing: Power plant technologies that have recently been constructed or are under construction or are being planned
- ***Provide outputs or services comparable with the CDM project activity***
  These include:
  Those alternatives that provide similar output in terms of the PLF, peak vs base load power and power quality
  Those alternatives for which the cost of generation is lower than grid power

§ ***In compliance with all applicable legal and regulatory requirements***

The options should be in compliance with the state and national policies on power generation and distribution.

Alternatives	Eligibility/Plausibility
The project activity not implemented as a CDM project activity by APCL	
Natural gas power generation using combined cycle system (Brayton cycle) without CDM Efficiency[2]: 45 – 52% Technical Life time: 15 years	Plausible and economical for higher capacities. Meets all eligibility conditions.
Power generation using natural gas, but technologies other than the project activity by APCL	
Natural gas power generation using IC engine technology Efficiency: 40-45% Technical Life time: 15 years	Not Plausible. It is not realistic and credible for the promoter. Combined cycle gas turbines are only economical for higher capacities due to their higher system efficiency compared to other technologies like IC engine technology.
Power generation technologies using energy sources other than natural gas by APCL	
Coal/Lignite based power plant (conventional) Efficiency[3]: 34 – 36% Technical Life time: 20-30 years	Plausible.
Coal based power plant with super critical boiler Efficiency: >40[4]% Technical Life time: 20-30 years	Not possible to have capacities similar to the project activity though it is emerging technology in the future and could be a possible plausible baseline scenario but with higher cost of power generation compared to conventional coal based power plant.
Nuclear power	Not Plausible. The national policy does not allow private sector power

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[2] http://www.infraline.com/power/default.asp?URL1=/power/overview0203.asp

[3] http://www.iea.org/textbase/work/2004/zets/apec/presentations/sharma.pdf

[4] Report of the committee to recommend next higher size of coal fired thermal power plant- issued by CEA, Ministry of Power, Government of India- www.cea.nic.in & appendix II to CERC guidelines – www.cercind.org.

Efficiency: 30% Technical Life time: 40 years[5]	generation in nuclear power.
Hydro power Technical Life time: 20-30 years	Not plausible. This option will not deliver outputs and services comparable to the project activity since hydro power plants are of seasonal nature with low plant load factors and involve higher capital cost and higher gestation periods.
Wind power Technical Life time: 15-20 years	Not Plausible. This option will not deliver outputs and services similar to the project activity since wind power plants are of seasonal nature with low plant load factors and involve higher capital cost. Also, it is not viable in the country like India without government subsidies.
DG set based power plant Efficiency: 35 – 40% Technical Life time: 20 – 30 years	Not Plausible. Not a realistic and credible alternative. This type of power plants are not in vogue; There are no DG based power plants constructed recently or are under construction or are being planned

From the above analysis, following are the plausible baseline scenarios identified for APCL:

- A coal based power plant supplying power to the present grid mix (Option 1)
- The project activity not implemented as a CDM project activity (Option 2)

Project Option 1 – Coal (fossil fuel) based power plant, supplying power to the present grid mix

In this scenario the end user would get power from the grid mix consisting of the project option 1 along with the present generation mix. Considering the present scenario of open tariff policy coupled with the fact that coal is the cheapest among all the available fossil fuel in the market this project option 1 is the most probable available option with project developer**.** Also, out of the total lignite reserves available in the country (around 30,300 million tons), 88% of the reserves are available in the state of Tamil Nadu. With the abundant availability of coal/lignite, it would be feasible to opt for setting up power plant with coal/lignite as fuel in the region. The average efficiency of power generation using coal as a fuel in the state is around 32.2% (with calorific value of coal as 3802 kcal/kg) and normal technical life time of the plant is around 25 years. And also, the efficiency of power generation using lignite as a fuel for generation is around 27.8%. With an increased thermal capacity addition of 119.8 MW coal based power plant, there would be an increase in the amount of carbon dioxide generated by the regional grid mix for

[5] Report of the expert committee on fuels for power generation (Chapter 3)

equivalent electricity. There are coal based power plants supplying electricity to grid. Hence, this project option is available with APCL.

Project Option 2 – Project activity not undertaken as CDM project activity

In this scenario the end user would get power from the grid mix consisting of the project option 2 along with the present generation mix. Project proponent would have implemented the project activity with less financial returns as this also meets all the requirements to set up the project.

From the above assessment we may conclude that APCL project activity has above project options:

Project **Option 1** – Fossil fuel (coal) based power plant, supplying power to the present grid mix

Project **Option 2** – Project activity not undertaken as CDM project activity.

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

The methodology prescribes to use investment analysis to identify the economically most attractive baseline scenario alternative. The levelized cost of electricity generation (Rs/kWh) of the alternatives are calculated and used as the financial indicators for comparison in the investment analysis. Detailed financial analysis of the identified feasible alternatives i.e. generation of power using coal has been carried out in a transparent manner and is given below. The detailed calculations of the same will be made available to validator during the validation stage.

Sl.	**ASSUMPTIONS**	**GAS Based Power Plant**		**COAL based Power Plant**	
1	Heat Rate	1936.5	Kcal/kWh	2500	kcal/ kWh
2	LCV	9300	Kcal/ SCM	3500	kcal/kg
3	Price	4000	Rs./1000 SCM	0.75	per kg
4	Capacity of plant	119.8	MW	300	MW
4	Appreciation percentage of US dollar against Rupee	4%	per year	4 %	per year
5	Increase in O&M cost and establishment cost	10%	Per year	4%	per year
6	Interest on INR loans	11.50%		10.00%	
7	Interest on foreign currency loans	10.50%		7%	
8	Depreciation	7.66%	per annum	3.60%	p.a
9	Auxiliary consumption	5.50%		9%	
10	Load factor	84%		80%	

Apart from above, the following are other parameters considered for calculations:

		Gas	Coal
Project capital cost	Rs. (Million)	4390	12900
Debt: Equity Ratio		70: 30	70: 30
Loan period	Yrs	10	10
Moratorium	Yrs	1	1

		Option # 1*		Option # 2*	
1	Per unit generation cost	1.69	Rs./kWh	1.79	Rs/kWh
2	IRR	**19.3**	**%**	**15.3**	**%**

**Option 1 – Fossil fuel (coal) based power plant, supplying power to the present grid mix*
Option 2 – Project activity not undertaken as CDM project activity.

The project activity without considering CDM revenues (*Option 2*) has the lowest financial indicator (higher cost of generation) among the alternatives. A sensitivity analysis has been performed to confirm the conclusion regarding the financial indicator.

Sensitivity analysis:

The sensitivity analysis of the financial indicators has been performed by subjecting them to reasonable variation in the critical parameters: plant load factor (PLF) and heat rate. The financial indicators are calculated for a 5% deviation in the heat rate and a 5% deviation in the PLF.

There is one more parameter which affects the sustainability of the project activity i.e change in the natural gas pricing. The prices of petroleum products have long since been controlled by the Government of India (GoI) under the Administered Pricing Mechanism (APM) to reduce the burden on the consumers. However, in April 2002 the GoI dismantled the APM on the oil derived fuels (petrol, diesel etc) after which there has been sharp increase in their prices to match international parity prices. This is the reason why fuel price change has also been included in the sensitivity analysis.

Parameter	Unit	5% increase in Heat Rate		5% decrease in Heat Rate	
		Option 1	Option 2	Option 1	Option 2
Average per unit generation cost	Rs./kWh	1.73	1.82	1.65	1.75

Parameter	Unit	5% increase in PLF		5% decrease in PLF	
		Option 1	Option 2	Option 1	Option 2
Average per unit generation cost	Rs./kWh	1.65	1.74	1.74	1.84

Parameter	Unit	5% increase in Fuel Price		5% decrease in Fuel Price	
		Option 1	Option 2	Option 1	Option 2
Average per unit generation cost	Rs./kWh	1.72	1.82	1.66	1.75

The sensitivity analysis confirms the result obtained in the investment analysis. The ***option 2:*** *"Project activity not implemented as a CDM project activity"* has the lowest financial indicator among the alternatives and remains so in circumstances subjected to reasonable variations in the critical techno-economic parameters. Therefore, it may be concluded that ***option 1***: *"Coal based power generation"* is the economically most attractive baseline scenario[6].

The prices of petroleum products have long since been controlled by the Government of India (GoI) under the Administered Pricing Mechanism (APM) to reduce the burden on the consumers. However, in April 2002 the GoI dismantled the APM on the oil derived fuels (petrol, diesel etc) after which there has been sharp increase[7] in their prices to match international parity prices. Presently gas supply price is at 40% of the international parity price. However, it is very likely that the GoI will dismantle the APM on gas in the next few years[8]. Such a move would make a impact on the power sector profitability since the selling price of electricity is not likely to increase proportionately.

[6] This is further confirmed by TNERC Tariff dated 15.03.2003 against TNEB petition No. "TP 1 of 2002" in which the generation cost (Rs/kWh) of various power plants in Tamil Nadu are provided.

[7] Since dismantling of APM in the oil sector, domestic petrol prices have increased by 63.5% and diesel prices by 83.5% till February 2006.

[8] The GoI has increased the APM price of natural gas by 12% in May 2005 for the power and fertilizer sectors and by 75% for the other consumers. The GoI decided to match the supply price to other consumers with international parity price and based on the market based price determination. It is very likely that the supply price to power and fertilizer sectors will also be matched with the international parity price shortly. This may result in a 50% to 100% increase in the gas supply price for the power and fertilizer sectors.

From the above analysis, it is clear that cost of power generation using coal is the cheapest option and the same is considered as the most economically attractive baseline scenario.

Application of additionality tests as mentioned in the methodology for proving the project additionality:

Project additionality as per the methodology has been described in the subsequent section (B.5).

Key parameters of the project activity:

Considering the guidelines of the methodology in view of the site/location- specific conditions of project activity, following are the key parameters and assumptions considered for the project activity which will affect the emission reductions.

- Estimation of present and future generation mix (grid/private supplier)
- IPCC CO_2 Emission Factors
- Cycle efficiency of the system
- Government policies/guidelines for Independent Power Producers (IPP's)
- As per the Electricity Act 2003, the projects, which have the lowest tariff, will be the preferred ones. Since the cost of power generation with coal as fuel is the lowest, most of the new projects will be set up with coal as fuel

The above parameters /assumptions are appropriately studied and considered for estimation of the emission reduction.

Estimation of CO_2 emission reductions due to supply of electricity to grid with lower emissions by the project:

Considering the project situation, formulae's are selected from the methodology and applied for estimation of emission reductions by project activity.

Further, as suggested in the methodology, emission factor estimation has been carried out using following three methods.

For the first crediting period:

Option 1: The build margin, calculated according to ACM0002; and
Option 2: The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight.
Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario" above,

Sl. No	Option	Value
1	Option 1: The build margin, calculated according to ACM0002	673.3 tCO2/MU
2	Option 2: The combined margin, calculated according to ACM0002, using a 50/50 OM/BM weight	845.0 tCO2/MU
3	Option 3: The emission factor of the technology (and fuel) identified as the most likely baseline scenario under "Identification of the baseline scenario	1048 tCO2/MU

As the BM factor of current generation mix is lower than the other two options, it has been selected as baseline emission factor on conservative basis. Detailed calculations are given in Annex 3.

Leakage emission is estimated as per the guidelines provided by the methodology and finally emission reduction due to project activity is estimated.

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

As per the selected methodology, the project proponent is required to establish that the GHG reductions due to project activity are additional to those that would have occurred in absence of the project activity as per the 'Tool for the demonstration and assessment of additionality (Version 02)' 28 November 2005. Additionality of project activity is discussed further.

Step 1 – Benchmark Investment Analysis:

For determining the benchmark, project proponent has taken into consideration all the financial parameters relevant to the project activity and has also conducted sensitivity analysis to gauge the impact of probable realistic fluctuation of key parameters. As per the detailed financial analysis, the project activity is less financially attractive than the comparable project activities since the returns of the power plant with NG as a fuel (project activity) is around 15.3% as against the returns of more than 16% for the comparable project activities considered (19.3% as given above for coal based power plant considered for comparison). All the power projects in India are considered viable only if the guaranteed returns of minimum 16%[9] on the capital are ensured.

[9] http://www.energywatch.org.in/india_powersector.htm; http://iis-db.stanford.edu/evnts/1565/India.pdf; http://timesofindia.indiatimes.com/articleshow/22269599.cms

The investment is also higher since advanced class energy efficient turbo generators and air cooled condensers are installed in the project activity. The project also has debt to equity ratio of 70:30, which may further increase the financial risk associated with the project activity. Some key financial figures for the project activity are given below.

Financing details of the Project	Power Plant
Total Cost of the project	Rs 4390 million
Debt: Equity Ratio	70:30
Return on investment	15.3%

The assumptions made while estimating the IRR of the project activity are given in the above section.

APCL conducted an investment analysis of the project activity with the Internal Rate of Return as the financial indicator. 'Internal Rate of Return' is one of the known financial indicators used by banks, financial institutions and project developers for making investment decisions.

APCL calculated the project activity's internal rate of return (IRR) and compared it with the returns for the comparable power projects considered i.e. more than 16%.

Calculation and comparison of financial indicators

The financial internal rate of return of the project activity without CDM revenues is 15.3% which is lower than the returns for the similar kind of comparable project activities as required by the investors. IRR is computed for 10 years of period. The period has also been selected based on the typical life time of the gas based power plants with optimum performance. This IRR is estimated with the present tariff structure and structure of the Administered Pricing Mechanism (APM). With the possible dismantle of APM by GoI in the near future; it is very likely that the IRR of the project will get affected significantly. This uncertainty demands for support for the project in terms of carbon credits for the sustainable operations.

The internal rate of return of the project activity with CDM revenues is around 18.9%. Therefore the project activity would only be financially viable if the project activity attains CDM revenue through sale of the emission reductions. With the availability of carbon credits, the financial viability of the project matches with the returns from other most attractive fuel options for power generation.

All financial data used to arrive at the internal rate of return of the project activity with and without CDM revenues would be provided to the DOE in the process of Validation.

Sensitivity analysis:

The project activity was found to be sensitive to the following factors –

1. Change in annual export to TNEB – Annual export to TNEB may alter due to change in gas availability patterns and any other unforeseen circumstances. It is very unlikely that the export to the grid will increase considerably in future under prevailing conditions and operating conditions. This increase in export to grid can happen only if the present auxiliary consumption, which is at optimum levels, is further reduced.
2. Change in heat rate
3. Change in fuel price

The sensitivity analysis was conducted for scenarios with variations in each one of the above-mentioned factors and for scenarios with variations in all the above-mentioned factors simultaneously in order to assess the financial attractiveness of the project activity under such circumstances.

Sl	Parameters	Variation	IRR	Comments
The financial internal rate of return of the project activity without CDM revenues				
1.	Annual Export to TNEB	- 5%	14.2%	The IRR of the project activity is lower than the returns from the comparable project activities
		+ 5%	16.5%	5% increase in export is very unlikely unless auxiliary consumption is reduced below present optimum levels.
2.	Heat rate	+ 5%	15.2%	The IRR of the project activity is still lower than the returns from the comparable project activities
		- 5%	15.4%	
3	Fuel price	+ 5%	15.2%	The IRR of the project activity is still lower than the returns from the comparable project activities
		- 5%	15.4%	

The results of the sensitivity analysis conducted confirm that the returns of the project activity without CDM revenues is much lower than the benchmark for the project activity as required by the investors for comparable project activities, under circumstances which could bring about variations in the critical factors used for the IRR computations. The sensitivity calculations for the above will be provided to validator during the validation stage.

The above facts and figures clarifies that the 'project activity is financially non viable activity' even with reasonable variations in the critical assumptions and hence CDM revenue is very crucial to sustain the operations of the project activity.

Step 2 – Common practice Analysis:

Step 4 of the latest "Tool for the demonstration and assessment of additionality" prescribes that activities similar to the project activity may be considered for the common practice analysis. Similar project activities are:

§ Private sector grid connected power plants
§ Of similar scale
§ That take place in a comparable environment with respect to regulatory framework, investment climate, access to technology etc: Within Tamil Nadu
§ Those activities that are implemented previously or currently underway

§ In the similar, project sector, socio-economic environment, geographic conditions and technological circumstances the project activity uses an energy efficient technology with higher costs, which has limited penetration. Natural gas based power plant accounts for 11% of total power generation in India[10].

o Coal-based power plants generate about 60% of the total capacity and around 80% of the total thermal capacity. This is because coal is available in abundance and is a cheaper fuel. The region wise status of power generation using coal and gas in India is as follows[11]:

Region	Total thermal power generation, MW	Generation using coal as fuel, MW	%generation using coal as fuel	Generation using gas as fuel, MW	Gas based installed capacity as % of total installed capacity
Northern	19143	15915	83	3213	10
Western	25845	20792	80	5035	16
Southern	16982	13393	79	2650	9
Eastern	15235	15027	97	190	1
North Eastern	1223	330	27	751	32
Island	64	0	0	0	0
All India	**78491**	**65456**	**83**	**11840**	**11**

[10] Source: cea.nic.in/gov/opm/thermal_performance_review/0405/cea_thermal%20performance%20review0405/section-10.pdf.

[11] Infraline's paper on "Natural gas for power sector: issues and challenges"

☑ From the above table, it is clear that percentage of power generation using coal is very high out of total thermal power generation in India. This indicates the popularity of the fuel mainly due to easy availability and low cost of generation than other fuel sources like gas, diesel etc. Therefore, in view of the methodology, the project activity is not a common practice which further determines that it is an additional activity.

☑ It is also clear from above table that similar activities i.e. power generation using gas as a fuel is not widely observed and is not commonly carried out. The reasons for low penetration of similar activities are explained in the above sections. All the power plants using gas as fuel in the country are facing the similar barriers described and discussed in earlier sections. In addition to above, the major hurdle in the growth of the industry has been uncertain regulatory environment. Also, low penetration of gas based power generation in the country is due to inadequate pipeline infrastructure.

☑ The percentage share of gas based power generation in the country during 9th five year plan, during 10th and 11th plans[12] are as follows:

Power from	% of Grid Mix			
	At the end of 9th Plan	As on 31.12.06	At the end of 10th Plan (likely)	At the end of 11th Plan (Estimated)
Gas	10.6%	11%	10.5%	10.0%

From the above table, it can be seen the share of power generation from gas is likely to be reduced by the end of 10th plan and 11th plan. This is mainly due to the government's plan to encourage coal based ultra mega power projects. From the above discussion, it is evident that gas based power generation is unlikely to become common practice in India considering abundant availability of cheaper fuels like coal.

☑ In addition, Aban Power has installed Air cooler condenser investing Rs. 10.76 crores as against Water condenser system which would have cost only Rs. 5 crores. This has been done considering zero ground water usage, minimum water consumption in spite of reduction in around 2 MW output. The annual impact of reduction in generation is 17.52 Million Units. Not many gas based plants in India have got air cooled condensers and most of the plants are with water cooled condensers.

☑ Plant uses High temperature F class gas turbine with the higher fuel efficiency than the standard E class turbines. Only three out of 38 combined cycle power plants (i.e. 8%) in India use such advanced class gas turbines.

[12] www.infraline.com (Indian Power Sector – Challenges and opportunities); http://cea.nic.in

- ☑ Aban Power has installed Dry Low NOx burners which specifically tunes the burners of the turbine, controls the formation of NOx at very low level, enhances the efficiency of the engine and does not use DM water or steam as in the conventional engines. These kind of burners are installed in very few gas based power plants in India.
- ☑ Project activity also consumes very less water per MWh generation and is totally zero discharge effluent plant. These kinds of facilities exist in very few gas based power plants in the country.

Thus the above substantiate the claim that the project activity is not a widely observed and commonly carried out practice. Therefore, this project is additional.

Step 3 – Impact of CDM registration:

The impact of CDM registration is determined with respect to possible realistic future development in the power sector. The legal framework governing the sector is Electricity Act-2003. As per the act the bulk purchase of power across the country should be done through competitive bidding process. This will have serious implication on financial parameters of all the NG based power plants in India. The principal aspects of concerns are described below.

As per this act, bulk purchase of power by SEB's should be routed through tendering process with selection of power supplier offering lowest rate on competitive basis. Since this act supports the power generation with lower tariff, the power generated by the cheaper but carbon emissive fossil fuels like coal and lignite will be purchased by the SEB's and individual bulk consumer with preference. As a result, the power generated using cleaner fuels like natural gas but with higher cost of generation will get the second priority from the buyers as its generation cost is higher than the generation cost with conventional fuels like coal and lignite.

The present direction of power sector reforms indicates further opening up of the power sector and a gradual shift towards more competitive environment. So in future to be in the competition the developers of NG based power plant may face serious pricing pressure. In this futuristic scenario, where the promoter may be forced to offer lower tariff than the present PPA, CDM funds will help to reduce the gap between the tariff offered by the project activity and the other power generators/suppliers which generate power with cheaper but high carbon emissive fuels like coal and lignite.

This justifies the need of CDM funds for the project activity, which will help to improve the project competitiveness and financial sustainability if the electricity tariff reduces in future.

The barriers as discussed above are strong enough to affect the sustainability of project. In absence of the project activity equivalent amount of electricity would have been generated using conventional fossil fuel to feed the same grid to which the project activity will supply electricity, leading to increase in GHG emission. In spite of facing lot of barriers the project promoter have gone ahead with the project and in the process have taken substantial financial risk. Therefore, the CCPP is an additional activity as it over comes the above barriers by taking up additional risk of implementation.

As the starting date of the project activity is before the date of validation, evidence about the management decision considering CDM benefits is necessary. A board resolution taken in 2002 testifies this decision.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Project activity adopted the procedures mentioned in the approved methodology (AM0029) to calculate project emissions, baseline emissions, leakage emissions and emission reductions.

The procedures used for calculating these emissions are described below:

Project emissions:

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

$$PE_y = \sum FC_{f,y} * COEF_{f,y} \quad (1)$$

Where:

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

$COEF_{f,y}$: is the CO_2 emission coefficient ($tCO2/m^3$ or similar) in year(s) for each fuel and is obtained

as:

$$COEF_{f,y} = \sum NCV_y * EF_{CO2,f,y} * OXID_f \quad (2)$$

Where:

NCV_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’ (tCO2/GJ) as determined from the fuel supplier, wherever possible, otherwise from local or national data;

$OXID_f$: is the oxidation factor of natural gas (as per latest IPCC guidelines)

For start up fuels, IPCC default calorific values and CO2 emission factors are acceptable, if local or national estimates are unavailable.

Baseline emissions:

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

$$BE_y = EG_{PJ,y} * EF_{BL,CO2,y} \quad (3)$$

As per the methodology the Baseline emission factor is chosen as the minimum of the following three

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

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

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

$$EF_{BL,CO2}\,(tCO_2 / MWh) = \frac{COEF_{BL}}{\eta_{BL}} * 3.6\,GJ / MWh \quad (4)$$

Where:
$COEF_{BL}$ = the fuel efficiency coefficient /tCO_{2e}/GJ), based on national average fuel data, if available, otherwise IPCC defaults can be used.
η_{BL} = the energy efficiency of the technology, as estimated in the baseline scenario analysis above.

For detailed calculation of build margin and combined margin as per ACM0002, please refer to the Annex 3. The values are calculated using the equations mentioned in ACM0002.

Estimation of Baseline Emission Factor:

So as to have conservative emissions, lower value of BM, CM and the value as per equation 4 has to be chosen as baseline emission factor.

BEF = lowest of (BM, CM, $EF_{BL,CO2}\,(tCO_2 / MWh)$) (5)

Leakage:

Leakage may result from fuel extraction, processing, liquefaction, transportation, re-gasification and distribution of fossil fuels outside of the project boundary. This includes mainly fugitive CH4 emissions and CO2 emissions from associated fuel combustion and flaring. In this methodology, the following leakage emission sources shall be considered.

Fugitive CH4 emissions associated with fuel extraction, processing, liquefaction, transportation, regasification 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: CO2 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:

$$LE_{y} = LE_{CH4,y} + LE_{LNG,C02,y} \qquad (6)$$

There will be no LNG consumption in the project activity, so $LE_{LNG,CO2,y}$ will be zero.

where

$LE_{CH4,y}$ Leakage emissions due to fugitive upstream CH4 emissions in the year y in t CO2e

Fugitive methane emissions

For the purpose of estimating fugitive CH4 emissions, project participants should multiply the quantity of natural gas consumed by the project in year y with an emission factor for fugitive CH4 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:

$$LE_{CH4,y} = \left[FC_{y} * NCV_{y} * EF_{NG,upstream,CH4} - EG_{PJ,y} * EF_{BL,upstream,CH4}\right] * GWP_{CH4} \qquad (7)$$

Where

$LE_{CH4,y}$	Leakage emissions due to fugitive upstream CH4 emissions in the year y in tCO2e
FC_{y}	Quantity of natural gas combusted in the project plant during the year y in m3
$NCV_{NG,y}$	Average net calorific value of the natural gas combusted during the year y in GJ/m3
$EF_{NG, upstream, CH4}$	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution and in the case of LNG, liquefaction, transportation, regasification and compression in to a transmission or distribution system, in tCH4 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 tCH4 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 ($EF_{BL, upstream, CH4}$) has been calculated consistently with the baseline emission factor ($EF_{BL,CO2}$) used in equation (4) above. The lowest baseline emission factor has been found to be the one calculated as per build margin method, so the same calculation procedure has been adopted to calculate $EF_{BL, upstream, CH4}$. The same has been described below.

$$EF_{BL,upstream,CH4} = \frac{\sum_{j} FF_{j,k} * EF_{k,upstream,CH4}}{\sum_{j} EG_{j}} \quad (8)$$

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
FFj	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
EGj	Electricity generation in the plant j included in the build margin in MWh/a plant included in the operating margin

The default values used in the project activity are as follows:

Sl. No	Parameter	Default Value	Remarks
1	Emission factor for fugitive CH_4 upstream emissions for coal	0.8 tCH_4/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.

Sl. No	Parameter	Default Value	Remarks
			(http://www.mbendi.co.za/indy/ming/coal/as/in/p0005.htm) . Hence 0.8 tCH4/kt coal value is used for surface mining
2	Emission factor for fugitive CH_4 upstream emissions for Oil	4.1 tCH_4/PJ	As per the Table 2 of the methodology. This value includes for oil production, transport, refining and storage.
3	Emission factor for fugitive CH_4 upstream emissions for Natural Gas	160 tCH_4/PJ	As per the Table 2 of the methodology, 296 tCH4/PJ is applicable for rest of the world and 160 tCH4/PJ is for USA and Canada. However, the US/Canada value is used as the system element (gas production and/or processing/ transmission / distribution) is predominantly of recent vintage and built and operated to international standards. GAIL is maintaining all its processing plants and gas transmission lines matching the international standards and are of recent vintage. GAIL also formulating a guidelines for the pipelines along with the BIS for development of uniform standards for high-pressure oil and gas transmission pipeline systems[13]. Also GAIL conducts the regular safety audits to maintain the international safety standards with some reputed international firms[14].
4	Oxidation factor of natural gas	1.0	IPCC value as per 2006 IPCC guidelines for National Green House Gas inventories

Emission Reductions:

To calculate the emission reductions the project participant shall apply the following equation:

$$ER_y = BE_y - PE_y - LE_y \quad (9)$$

Where:

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

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

The following are the list of data and parameters that are not monitored throughout the crediting period but that are determined only once and thus remains fixed throughout the credit period and that are available when validation is undertaken.

[13] http://www.blonnet.com/2005/04/23/stories/2005042301550200.htm

[14] http://www.energymanagertraining.com/eca2005/Award2005CD/AwardBook/Petroleum%20Pipeline.pdf

Data / Parameter:	**$EF_{CO2,f,y}$**
Data unit:	tCO_2/TJ
Description:	Emission factor of natural gas used to estimate project emissions
Source of data used:	IPCC
Value applied:	56.1
Justification of the choice of data or description of measurement methods and procedures actually applied :	IPCC default value of the current year is considered as there is no national data available for the emission factor of the fuel used.
Any comment	-

Data / Parameter:	**$EF_{NG,Upstream,CH4}$**
Data unit:	tCH_4/GJ
Description:	Emission factor for upstream fugitive methane emissions of natural gas from production, transportation, distribution ($EF_{NG,Upstream,CH4}$)
Source of data used:	If reliable and accurate national data on fugitive CH_4 emissions associated with the production, and in case of natural gas, the transportation and distribution of the fuels is available, project participants uses this data to determine average emission factors by dividing the total quantity of CH_4 emissions by the quantity of fuel produced or supplied respectively. Where such data is not available, project participants uses the default values provided in table 2 in the methodology
Value applied:	160 tCH_4/TJ
Justification of the choice of data or description of measurement methods and procedures actually applied :	GAIL is maintaining all its processing plants and gas transmission lines matching the international standards. GAIL also formulating guidelines for the pipelines along with the BIS for development of uniform standards for high-pressure oil and gas transmission pipeline systems[15]. Also GAIL conducts the regular safety audits to maintain the international safety standards with some reputed international firms[16].
Any Comment	-

B.6.3 Ex-ante calculation of emission reductions:

The ex-ante calculation of project emissions, baseline emissions and leakage emissions expected during the crediting period, applying all relevant equations provided in the approved methodology are provided in **Enclosure – 1**.

[15] http://www.blonnet.com/2005/04/23/stories/2005042301550200.htm

[16] http://www.energymanagertraining.com/eca2005/Award2005CD/AwardBook/Petroleum%20Pipeline.pdf

The total project activity emission is estimated to be 396,249 ton CO_2 e per annum.

The baseline emission estimated in a conservative manner as described in above sections. The most conservative estimate has been found to be the build margin factor. The estimated baseline emission is 588,215 ton CO_2 e per annum.

The estimated leakage in the project activity is taken as 10,813 tCO_2e per annum.

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

Year	Estimation of Project Activity Emission (tonnes CO_2 e)	Estimation of Baseline Emission (tones of CO_2 e)	Estimation of Leakage (tones of CO_2 e)	Estimation of overall Emission Reductions (tones of CO_2 e)
2006	396249	588215	10813	181153
2007	396249	588215	10813	181153
2008	396249	588215	10813	181153
2009	396249	588215	10813	181153
2010	396249	588215	10813	181153
2011	396249	588215	10813	181153
2012	396249	588215	10813	181153
2013	396249	588215	10813	181153
2014	396249	588215	10813	181153
2015	396249	588215	10813	181153
Total (tonnes of CO2e)	3962490	5882150	108130	1811530

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

Title: Approved monitoring methodology AM0029 (Version 1.1) "Grid Connected Electricity Generation Plants using Non-Renewable and Less GHG Intensive Fuel."

This methodology also uses the build margin (BM) approach as specified in ACM0002, with annual ex-post determination of baseline emission factor, and the "tool for the demonstration and assessment of additionality"

The project activity is Natural gas (Cleaner fuel) based power generation project, which feeds surplus electricity (power) to the Tamil Nadu state grid (comprising power generated through sources such as coal, lignite, diesel and gas based thermal power, hydro power and renewable energy sources including small/micro hydro projects, bagasse/biomass based cogeneration/power projects etc).

The project activity meets the methodology applicability criteria as under:

- The project activity is the construction and operation of a new natural gas fired grid-connected electricity generation plant and erecting a transmission line for power evacuation.
- The geographical/ physical boundaries of the baseline grid are clearly identified and information pertaining to the grid and estimating baseline emissions is publicly available.
- Natural gas is sufficiently available in the southern region of India. 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.

All the data to be monitored to estimate 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 the project activity, whichever occurs later.

B.7.1 Data and parameters monitored:

The following tables include specific information on how the data and parameters that need to be parameters would actually be collected during monitoring for the project activity. Only data that is determined only once for the crediting period but that becomes available only after validation of the project activity are included here.

Data / Parameter:	**$FC_{f,y}$**
Data unit:	m^3
Description:	Annual quantity of fuel "f" consumed in project activity
Source of data to be used:	Fuel flow meter reading at project boundary
Value of data applied for the purpose of calculating expected emission reductions in section B.5	As per plant records
Description of measurement methods and procedures to be applied:	The total fuel consumption will be monitored both at supplier and project end for cross verification and measured in standard cubic meters
QA/QC procedures to be applied:	Natural gas supply metering to the project will be subject to regular (in accordance with stipulation of the meter supplier) maintenance and testing to ensure accuracy. The readings will be double checked by the gas company.
Any comment:	-

Data / Parameter:	**NCV_y**
Data unit:	GJ/m^3 (or kcal/scm)
Description:	Net calorific value of fuel type f
Source of data to be used:	Fuel supplier
Value of data applied for the purpose of calculating expected emission reductions in section B.5	As per plant records
Description of measurement methods and procedures to be applied:	The calorific value of the gas would be provided by the supplier and recorded and verified by the project participant
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	-

Data / Parameter:	**$EF_{CO2,f,y}$**
Data unit:	$tCO2/m^3$
Description:	CO2 emission coefficient
Source of data to be used:	Calculated under project activity
Value of data applied for the purpose of calculating expected emission reductions in section B.5	Calculated based on equation 2a in the methodology, Refer Annex 3
Description of measurement methods and procedures to be applied:	Will be calculated based on the standard procedures available
QA/QC procedures to be applied:	No additional QA/QC procedures may need to be planned
Any comment:	-

Data / Parameter:	**$EG_{PJ,y}$**
Data unit:	MWh
Description:	Electricity exported to grid by the project activity
Source of data to be used:	Data measured and recorded from Energy meters installed in the plant and in substation
Value of data applied for the purpose of calculating expected emission reductions in section B.5	As per plant records
Description of measurement methods and procedures to be applied:	Electricity supplied by the project activity to the grid. Double check by receipt of sales
QA/QC procedures to be applied:	Meters will be calibrated as per the standard procedures and documents for the same will be maintained throughout.
Any comment:	-

Data / Parameter:	**$OXID_f$**
Data unit:	-
Description:	Oxidation factor of natural gas used to estimate project emissions
Source of data to be used:	IPCC
Value of data applied for the purpose of calculating expected emission reductions in section B.5	1.0
Description of measurement methods and procedures to be applied:	IPCC default value of the current year is considered. The same was suggested in 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.
QA/QC procedures to be applied:	-
Any comment:	Oxidation factor of the gas will be updated as per the latest guidelines available from IPCC on national greenhouse gas inventory on year to year basis.

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 M&V Protocol provides a range of data measurement, estimation and collection options/techniques in each case indicating preferred options consistent with good practices to allow project managers and operational staff, auditors, and verifiers to apply the most practical and cost-effective measurement approaches to the project. The aim is to enable this project have a clear, credible, and accurate set of monitoring, evaluation and verification procedures. The purpose of these procedures would be to direct and support continuous monitoring of project performance/key project indicators to determine project outcomes, greenhouse gas (GHG) emission reductions.

The project revenue is based on the units exported as measured by power meters at plant and check meters at the existing substation of the TNEB. The monitoring and verification system would mainly comprise of these meters as far as power export is concerned. The natural gas input will also be monitored. The export of electricity will be through invoices to APCL. The invoices, based on meter readings will also be covered in the regular finance audit.

The measurement of the quantity of natural gas used will produce evidence that the energy is being generated with reduced CO2 emissions as compared to selected grid emissions.

The project employed latest state of art monitoring and control equipment that measure, record, report, monitor and control various key parameters. Parameters monitored are quantity and quality of fuel used, total power generated, power exported to the grid from the project, etc. These monitoring and controls are part of the Distributed Control System (DCS) of the entire plant. All monitoring and control functions are done as per the internally accepted standards and norms.

The instrumentation and control system available comprises of microprocessor-based instruments of reputed make with desired level of accuracy. All instruments will be calibrated and marked at regular intervals so that the accuracy of measurement can be ensured all the time.

The quantity of emission reduction units claimed by the project will be only a fraction of the total generated emissions, which depends on the actual generation mix of the grid in a particular year. Required information about the performance of power generation units of Southern grid (which include both private and public sector generation units of the grid) is available in the yearly publication of Central Electric Authority (CEA) of India. Hence, authentic data related to the measurements, recording, monitoring and control of the generation mix of the Southern network will be ensured.

The CEA report contains all information regarding type of generation like hydro, thermal, nuclear, renewable etc., installed capacity, de-rated capacity, performance of generating unit, actual generation, capacity additions during the year, etc. which will be used for verification of generation mix and emission factors for baseline calculation for a particular year.

Identified Project GHG Sources:

a) Direct On-Site Emissions:

Direct on-site emissions of the project arise from the combustion of natural gas in the gas turbine. These emissions mainly include CO2.

No other GHG emission will be taking place at the project activity site.

b) Direct Off-Site Emissions:

Direct off-site emissions are those emissions, which are significant and reasonably attributable to the project activity, but are not included in the project boundary. These emissions are also called as leakages. As per the boundary defined for the project, direct on-site emission arises during the transport of natural gas. However, in the baseline of power generation, fuel transport will take place, which has to be taken into account. On an average, the distance over which fuels have to be transported will be larger for fossil fuel-fired power stations, contributing to baseline emissions because of a large distance to coal mines and ports. As against natural gas transportation (by pipeline) will contribute to negligible emission of CO2 (due to operation of gas blowers at gas terminal point).Transport emissions of the baseline will be much more than the transport emissions related to the project activity. To provide a conservative estimate of the emission reductions, the reduction in transport emissions in the project compared to the transport emissions in the baseline is not taken into consideration for CO2 emission reduction estimate of the project. Transport emissions are therefore not taken into account.

c) Indirect On-Site Emissions:

The indirect on site GHG source is the consumption of energy and the emission of GHGs involved in the construction of natural gas based combined cycle power plant.

Considering the life cycle assessment of the total power generated and the emissions to be avoided in the life span of 15 –20 years, emissions from the above-mentioned source are too small and hence neglected.

No other indirect on-site emissions are anticipated from the project activity.

d) Indirect Off-Site Emissions:

The indirect off-site GHG source is the emission of GHGs that are involved in the process, construction and erection of the transmission lines from the nearest sub station, up to the point from where the project wheels the power. This is an emission leakage.

Considering the life cycle assessment of the total power generated and the emissions to be avoided in the life span of project, emissions from this source is also too small and hence neglected.

The electricity generated, less the auxiliary consumption, will be exported to the southern grid through TNEB to meet the increasing demand of electricity services, and there will be no creation of new activities or demand in other places / sites caused by the project.

Project Parameters affecting Emission Reduction:

Fuel Used

The major fuel to be used by the plant is Natural Gas.

The Natural Gas (about 5,00,000 Sm^3 per day) for the power generation is supplied at the plant boundary, through a dedicated pipeline, by GAIL (India) Limited, from a gas station of Oil and Natural Gas Commission (ONGC) located at Kuttalam, which is about 8 kms from the plant site.

The following parameters will be monitored at the gas receiving station.

- Calorific value of NG
- Flow of natural gas to APCL

Southern region have ample reserve of natural gas to sustain the successful running of the plant.

Quantity of the fuel used in the Gas Turbine

Based on natural gas analysis and the configuration considered in Detailed Project Report (DPR), the requirement of gas fuel for 119.8 MW Capacity (Nominal Gross Site Rating) is estimated to be 500000 Sm3 per day.

Natural gas is supplied by ONGC through its pipeline from gas wells up to the power plant boundary. Fuel gas supplier have the necessary pressure regulation, conditioning and tariff gas metering station at their gas supply terminal near power plant to ensure proper monitoring and quantification of gas intake in the power plant.

The Proprietary control system for gas turbine includes electronics required for data acquisition, processing and control, sequence starting of the equipment and comprehensive alarm indication. It would be possible to execute performance-monitoring functions in control system. Start-up, shutdown and normal operation would be possible from the GTG (Gas Turbine Generator) control system and would be monitored from the DCS. The system would be capable of measuring accurate gas fuel flow. The data will be recorded for further verification.

NG used in the gas Turbine

The main type of fuel used for the power generation is only NG. The properties of NG like chemical composition, calorific value etc. varies from well to well. The performance of GTG will also depend on the properties of the NG used as fuel.

Total power generated:

The total power generated by the power project will be measured in the plant premises to the best accuracy and will be recorded, monitored on a continuous basis through DCS. All measurement devices will be microprocessor based with best accuracy. All instruments will be calibrated at regular intervals. The parameter will substantiate the smooth operations of the project. During verification, the total power generated would be verified as compared to the power exported to the grid.

Power consumed by the plant auxiliaries:

The power consumed by plant auxiliaries will be recorded in the plant premises to the best accuracy. This will be recorded monitored on a continuous basis through DCS. All measurement devices will be microprocessor based with best accuracy. All the instruments will be calibrated at regular intervals. The total quantum of power consumed by the auxiliaries would affect the total power exported to the grid and in turn the amount of GHG reductions. Therefore any increase in the consumption pattern of the auxiliary system would be attended to.

Power exported to the grid:

The project revenue will depend on net units exported to power off taker. All metering and check metering facilities will be installed within the plant premises as well in the TNEB grid substation through which power will be evacuated to southern grid. The measurement will be recorded and monitored on a continuous basis through DCS. The actual net quantity of power exported will be arrived at after joint verification of data by both APCL and TNEB.

Efficiency and Heat rate of the project activity:

Based on the measured input and output parameters, plant system efficiency and Heat rate will be calculated and monitored by DCS. In case of any irregularity, the root cause of the deviations would be identified and the necessary corrective actions are taken.

All the above parameters / factors will demonstrate the performance of the project at any point of time.

Verification:

The performance of the NG based combined cycle power project leads to CO_2 emission reductions. In other words, if the power plant operates at high PLF and high efficiency and exports power to the grid, more emission reductions would be possible. The project control system will comprise of a sophisticated control and monitoring system like Distributed Control System (DCS) which measures, collects the information about various process parameters, records, monitors and controls on a continuous basis.

The major activities and parameter that are to be verified are listed below:

Activities:

- Verification of various measurement and monitoring methods
- Verification of instrument calibration methods
- Verification of data generated by DCS
- Verification of measurement accuracy

Parameters:

- Quantity of the NG used
- Efficiency and heat rate of the power plant
- Total power generation and captive power requirements.
- Power exported to the grid

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)

Date of completion of baseline study and monitoring methodology: 27/07/2006
Aban Power Company Limited has determined the baseline and monitoring methodology for the project activity. The entity is a project participant listed in Annex-I where the contact information has also been provided.

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:

>> Start date of the project: 05/05/2003

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

>>15 years

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

C.2.1. Renewable crediting period

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

>> Not used

C.2.1.2. Length of the first crediting period:

>>Not applicable

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

>>01/01/2006 (Considering 4 months of Stabilization period)

C.2.2.2. Length:

>>10 years

SECTION D. Environmental impacts

>>

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

>> In order to obtain the required clearance from the Ministry of Environment & Forest (MoEF), Government of India (GoI), an EIA Report is a statutory prerequisite. Thus, the Rapid Environmental Impact Assessment (REIA) study is aimed at predicting the possible environmental impacts due to construction and operation of the project, suggesting environmental remedies/safeguards and formulating an effective Environmental Mitigation Plan to ensure an environmentally sustainable development.

The major environmental disciplines studied include geology, soils, surface and ground water hydrology, meteorology, land use, surface and ground water quality, air quality, terrestrial and aquatic ecology, demography and socioeconomics and noise.

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:

>>Host party regulations requires APCL to obtain environmental clearance in the form of "No objection Certificate" from Tamil Nadu Pollution Control Board. The other condition is that the site of the project is to be approved from the environmental angle and that the Environmental Management Plans are to be prepared and submitted to the pollution control board. Environmental Impact Assessment has been conducted for the project activity and the study indicates that the impacts of the project are not significant. The assessment of environmental impact due to the project activity has been carried out to understand if there are any significant environmental impacts and a management plan has been prepared to minimise adverse environmental impact.

The findings of the EIA are summarised below.

Sl No	Component of environment	Possible Impact (Phase wise)		Measures taken by APCL
		Construction Phase	Operational Phase	
1	Soil	• Soil erosion • Decreased permeability	• Soil contamination from sludge discharge • Change in pH level of soil due to deposition of air pollutants	• The impacts during construction stages were localised in nature and not posed any significant long term threat over a period of time. • The discharged sludge is not expected to contain any obnoxious substance to contaminate the soil. The NOx level was well within the permissible levels and did not have any adverse effect on soil. • As a precautionary measure, however, soil samples will be periodically collected from close to the maximum deposition areas of air pollutants and analysed for relevant parameters during the post operational monitoring
2	Hydrology	• No significant impact on surface hydrological conditions • The possibility of slight depletion of ground water table as water for construction will be drawn from ground water source	• impact on the surface hydrological conditions for the withdrawal of water for running the plant • No impact on groundwater conditions during operational phase	• The slight depletion of ground water table during construction phase is only temporary, and is negligible in the long run • The impact on the surface hydrological conditions would be felt marginally during operational phase.
3	Water	• Discharge of untreated sewage would result in faecal contamination that could lead to development of waterborne diseases as cholera, typhoid etc	• The possible contamination of water due to effluent discharge in the river. • The possible groundwater contamination for improper disposal of sludge.	• In order that no adverse environmental impacts are created due to setting up of this plant through improper sanitation, drainage etc, the settlements are provided with suitable provision of essential basic amenities as water supply, sewerage and drainage system and solid waste disposal arrangements • The different plant effluents are subjected to various forms of treatment and would be

Sl No	Component of environment	Possible Impact (Phase wise)		Measures taken by APCL
		Construction Phase	Operational Phase	
				monitored to conform to more than the applicable discharge standards as per EPA, 1986. • The impact from water is due to plant waste water like service water and sanitary effluent totalling up to 168 m^3/day. Sanitary waste water will be let into a septic tank and the overflow into the STP. Service waste water also will flow into the ETP system. Total quantity of service water and sanitary waste water is about 7 m^3/hr. About 6.5-m3/hr water will be taken to RO (Reverse Osmosis) Plant and out of this 5 m^3/hr water will be recycled to Demineralisation (DM) plant. The ETP system consists of guard pond, aerator tank with a surface aerator, RO plant and solar evaporation pond. In the aeration tank, due to aerobic degradation of organic matter, BOD and COD levels will come down and after settling of suspended solids in the settling tank, the supernatant water from this tank will be let out for gardening and green belt development within the plant premises as the quality of water will conform to the permissible limits as per Indian Standard IS-2490.
5	Air	• Suspended particulate matter generation because of various construction activities. • Air pollution because of exhaust from vehicular movements during the construction	• Air pollution from combustion of natural gas.	• During construction suitable dust suppression system through atomized sprinklers was installed at the major dust generation points. The plant area was watered from trucks through water sprays. • The pollution due to vehicular exhausts and other related activities during construction phase was negligible, when compared to dust.

Sl No	Component of environment	Possible Impact (Phase wise)		Measures taken by APCL
		Construction Phase	Operational Phase	
		activities		• Tall stack of 38 metres height for wider dispersal of pollutants, resulting in lower ground level concentrations. • Low NOx burners would be used to limit NOx emissions to only 50 ppm.
8	Demography and socio economics	• Demographic changes due to sudden influx of population • Effect of necessary resettlement	• The demographic impact on the plant site and in the nearest cities for the plant.	• The demographic impact on the area during construction phase will be marginal. • The demographic impact on the existing community and its surrounds are unlikely to feel any significant impacts during the operational phase of the project activity.
9	Noise	• Noise pollution from heavy earth moving and construction machineries. • Noise pollution from blasting operation	• High noise generation from turbine generator and cooling tower	• Careful scheduling of the operation of the high noise machines was done during this period, particularly during night time, so that minimum disturbances are caused. To reduce noise pollution from blasting, noise absorbers were used between the foundation and the earth/soil. This would appease impacts due to noise and vibrations on the nearby villages. • Impacts on persons working very close to the sources are likely. Therefore, the latter would be provided with adequate protection against noise in the form of ear plugs, helmets etc.

SECTION E. Stakeholders' comments

>>

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

>> Identification of Stakeholders

The 119.8 MW natural gas based combined power plant is implemented by APCL. The project uses natural gas as a fuel, which will be supplied by GAIL (India) Limited. The GHG emissions of the combustion process, mainly CO_2, will be substantially less as compared to any other fossil fuel based power plant. The fuel is clean, therefore there is no likelihood of suspended particulates in the stack gases.

The stakeholders identified for the project are as under.

- Elected body of representatives administering the local area (village *Panchayat*)
- Tamil Nadu Electricity Board (TNEB)
- Tamil Nadu Pollution Control Board (TNPCB)
- Environment Department, Government of Tamil Nadu
- Non-Governmental Organisations (NGOs)
- Consultants
- Equipment Suppliers
- Local community

Stakeholders list includes the government and non-government parties, which are involved in the project at various stages. APCL applied / communicated to the relevant stakeholders to get the necessary clearances.

All the identified stakeholders are invited by APCL through letters by post on 26th June 2006 explaining the purpose of the meeting. APCL has conducted a stakeholder consultation process in an open and transparent manner on 30/06/2006 at their company conference hall. They have invited all identified stakeholder explaining clearly about the project and sought their view on the project. The meeting was attended by the representatives of the identified stakeholders. The detailed report of stakeholder consultation will be made available to the validator on request.

E.2. Summary of the comments received:

>> ***Stakeholders Involvement***

The village Panchayat /local elected body of representatives administering the local area have provided their consent / permission to set up the project as evident from the public hearing document. Hence APCL has already completed the necessary consultation and documented their approval for the project.

Local population comprises of the local people in and around the project area and it also includes local manpower working at the plant site. Since, the project will provide good direct and indirect employment opportunities the local populace is encouraging the project.

The project did not require any major displacement of local population. The project has been established in a separate land owned by APCL therefore no new / additional land has been procured for the project. In addition, the local population is also an indirect consumer of the power that is supplied from the power plants. This is essentially because the power sold to the grid is expected to improve the stability in the local electricity network. Since, the distance between the electrical substation for power evacuation and the plant is not very high, installation of transmission lines has not created any inconvenience to the local population.

The project has therefore not caused any adverse social impacts on local population and has rather helped in improvising their quality of life.

For setting up the combined cycle power plant a number of statutory and non-statutory clearances were required which are listed below:

The Government of Tamilnadu has accorded permission for establishing the cogeneration facility at APCL power plant in karuppur village.

Tamilnadu Pollution Control Board (TNPCB) and Environment Department of Government of Tamilnadu have prescribed standards of environmental compliance and monitor the adherence to the standards. The project has received the No Objection Certificate (NOC) from TNPCB to Operate. This project has received the consent to operate under the Section 21 of the Air (Prevention & Control of) Pollution Act 1981 and under the Section 25/26 of the Water (Prevention & Control of) Pollution Act 1974.

State's apex body of power is Tamilnadu Electricity board and they have already issued consent for the installation of power plant of 119.8 MW as per section 44 of the Indian Electricity Supply Act 1948.

As a buyer of the power, the TNEB is a major stakeholder in the project. They hold the key to the commercial success of the project. TNEB has already cleared the project and APCL has already signed Power Purchase Agreement (PPA) with TNEB.

Project consultants were involved in the project to take care of various pre contract and post contract project activities like preparation of Detailed Project Report (DPR), preparation of basic and detailed engineering documents, preparation of tender documents, selection of vendors / suppliers, supervision of project implementation, successful commissioning and trial runs.

Equipment suppliers have supplied the equipments as per the specifications finalized for the project and were responsible for successful erection and commissioning of the same at the site.

Stakeholders' Comments

All the stakeholders were happy in knowing that a CDM project activity in their locality is contributing to a global cause and they commended the APCL management for their initiatives in the areas of climate change and sustainable development. In particular, the stakeholders lauded the project promoters for the environment friendly measures like air-cooled condensers, rain water harvesting and zero-discharge. A brief description of the issues raised by the stakeholders and the corresponding explanation by the project participants are described in brief in section E.3.

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

>>

Presented below in brief the issues raised by the stakeholders and the clarification provided by project promoters.

Queries of Stakeholders	Clarification provided by APCL
The project activity is presently operating without any negative environmental impacts. Will there be any negative environmental impacts in the future?"	The project has been designed to operate without any negative environmental impact. All the pollution control equipments will be operated as per standard procedures and maintained in a good working condition, which guarantees the continued operation of the project without negative impacts on the environment"
"Is the water required for the power plant taken from the local ground water resources?"	The power plant has been designed to operate with a very less quantity of water as compared to conventional power plants. This is made possible through the use of air-cooled condensers against the normal practice of water-cooled condensers. The plant requires minor quantity of water as

Queries of Stakeholders	Clarification provided by APCL
	make-up water for steam generation which is purchased from the TWAD. APCL doesn't use bore wells or other local ground water resources. In fact, APCL has constructed a rain water harvesting facility (18000 kL) in its premises which is used to recharge the local ground water table in percolation ponds. APCL has implemented the above measures keeping in mind that the surrounding region is dependent on agriculture for its livelihood for which ground water is a vital resource."
Is waste water/effluent being released in to the ground? Some industries store effluents in lagoons from which pungent smell arises after a period of time. Will the same happen at APCL plant?"	Boiler blow down is the major source of waste water from the plant. The waste water is treated in RO plant and the resulting water is evaporated in solar drying beds. Waste water from domestic usage (cleaning/washing/toilets) are treated in a STP and used for irrigation of the green belt. APCL is a Zero-Discharge project with no solid or liquid effluents released outside. There is no storage of effluent/waste water that may result in pungent smell or ground water pollution"
How is the power supply situation in the area improved by the project activity?"	APCL is located in a rural setting away from large power plants. The de-centralization of power generation results in improving the power quality. Prior to the project activity, the household supply voltage in the region was very low that Fluorescent lamps , agricultural pumps and household appliances failed to start. Now, with the load end location of the APCL power plant, the supply voltage has improved considerably enabling the operation of electrical appliances. Moreover, the power deficit in the region has been reduced to a large extent by APCL's power plant"

The relevant comments and important clauses mentioned in the project documents/clearances like Detailed Project Report (DPR), environmental clearances, power purchase agreement, local clearance *etc*. were considered while preparation of CDM project development document.

The APCL representative met the local NGOs and apprised them about the project and sought their support for the project.

As per UNFCCC requirement the PDD will be published at the validator's / UNFCCC web site for public comments.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Aban Power Company Limited
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<u>Annex 2</u>

INFORMATION REGARDING PUBLIC FUNDING

No public funding is available from countries listed in Annex I of Kyoto Protocol

Annex 3

BASELINE INFORMATION

Methodology suggests that in order to estimate the baseline emission factor for the first crediting period, the emission factor should be considered lowest among the following three options:

Option 1: The Build Margin, calculated according to ACM0002; and

Option 2: The Combined Margin, calculated according to ACM0002, using a 50/50 OM/BM weight

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

As a part of Option 1 and Option 2 calculations, complete analysis of the system boundary's electricity generation mix has been carried out for calculating the emission factor of Southern Regional Grid as follows:

OPTION 1: BUILD MARGIN & OPTION 2: COMBINED MARGIN

Step 1: Calculation of Operating Margin

As mentioned in the methodology, the project activity would have some effect on the Operating Margin (OM) of the Southern Regional Grid. The approved baseline methodology of AM0029 requires the project proponent to calculate the Build margin and Operating Margin (OM) emission factor following the guidelines in ACM0002 (Consolidated methodology for grid-connected electricity generation from renewable sources).

As per Step 1 of ACM0002, the Operating Margin emission factor(s) ($EF_{OM,y}$) is calculated based on one of the four following methods:

a) Simple OM, or
b) Simple adjusted OM, or
c) Dispatch Data Analysis OM, or
d) Average OM.

The baseline adopted for the project activity, which is the Southern Regional Grid was found to be dominated by fossil fuel based power plants. The low operating cost and must run resources which typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation constituted

23.63 %, which is less than 50% of the total grid generation and the data in the Table 1 illustrates the same.

As per the methodology, ‘Dispatch Data Analysis’ (1c) is the first methodological choice. However, this method is not selected for OM emission factor calculations, as the share of low cost / must run resources of the selected grid over the past five years (2000-01 to 2004-05) has been found to be 23.63%, which is less than 50% of the gross grid generation. This meets the condition as stipulated by the selected methodology, for using the simple OM method for calculating the operating margin emission factor as against the dispatch analysis method.

‘Simple OM’ (1a) method is applicable to project activity connected to the project electricity system (grid) where the low-cost/must run resources constitute less than 50% of the total grid generation in 1) average of the five most recent years, or 2) based on long-term normal for wind power production.

The Simple adjusted OM (1b) and Average OM (1d) methods are applicable to project activity connected to the project electricity system (grid) where the low-cost/must run resources constitute more than 50% of the total grid generation. To select the appropriate methodology for determining the Operating Margin emission factor (EFOM,y) for the project activity, APCL conducted a baseline study, wherein the power generation data for all Power sources in the project electricity system were collected from government/non-government organisations and from authentic sources and then analysed.

Amongst the ‘Simple OM’ (1a), ‘Simple adjusted OM’ (1b) and ‘Average OM’ (1d) methods to calculate the Baseline Emission Factor of the chosen grid, APCL has therefore chosen and adopted the ‘Simple OM’ (1a) method.

The Simple OM emission factor (*EFOM,simple,y*) is calculated as the generation-weighted average emissions per electricity unit (tCO2/MU) of all generating sources serving the project electricity system, not including low-operating cost and must-run power plants. The generation data for various power generating stations constituting the Southern Regional grid, that have been used in calculating the baseline emissions for the most recent three years:

Table 1: Power generation Mix of Southern Grid for five years					
Energy Source	**2000-01**	**2001-02**	**2002-03**	**2003-04**	**2004-05**
Total Power Generation (MU)	130371.1	133480.4	137321.71	142812.00	150372.74
Total Thermal Power Generation (MU)	83291.59	84031.63	92053.19	95898.00	97448.01
Total Low Cost Power Generation[17] (MU)	37098.75	34984.16	26959.92	26740.00	37766.21
Thermal % of Total grid generation	63.89	62.95	67.03	67.15	64.80
Low Cost % of Total grid generation	**28.46**	**26.21**	**19.63**	**18.72**	**25.12**
% of Low Cost generation out of Total generation - Average of the five most recent years –23.63%					
Data Source for the years 2000-01, 2001-02, 2002-03, 2003-04 & 2004-05: CEA, APTRANSCO, TNEB, KPTCL					

The Simple OM emission factor can be calculated using either of the two data vintages for years(s) *y*:

• A 3-year average, based on the most recent statistics available at the time of PDD submission, or the year in which project generation occurs, if $EF_{OM,y}$ is updated based on ex post monitoring.

APCL has calculated the OM emission factor as per the 3-year average of Simple OM calculated based on the most recent statistics available at the time of PDD submission. The following Table 2 presents the key information and data used to determine the Simple OM emission factor:

Table 2: Key information and data used to determine simple OM emission factor						
	2002-03		2003-04		2004-05	
Sector	MU	%	MU	%	MU	%
Thermal Coal Based-State	54403.766	39.06	54053	37.85	54077.42	35.96
Thermal Coal Based-Central	21578.237	15.49	24054	16.84	25291.93	16.82
IPP-Coal Based	472.294	0.34	0	0.00	0	0.00
IPP-Gas Based	16182.487	11.62	16949	11.87	12794.41	8.51
Lignite based power plant	15375.106	11.04	17791	12.46	18078.66	12.02
IPP-Diesel Based	4688.043	3.37	3225	2.26	2364.11	1.57
Hydro-State	18305.244	13.14	16630	11.64	25279.78	16.81
Nuclear Based-Central	4379.39	3.14	4700	3.29	4406.43	2.93
IPP-Co-Generation + BIOMASS	2396.94	1.72	1910	1.34	2080	1.38
IPP-Wind	1494.664	1.07	3500	2.45	6000	3.99
Total	139276.2	100.00	142812.0	100.00	150372.7	100.00
Total generation excluding Low-cost power generation	112699.93	80.92	116072.00	81.28	112606.53	74.88
Generation by Coal out of Total Generation excluding Low-cost power generation	76454.30	54.89	78107.00	54.69	79369.35	52.78

[17] Low-cost/must run resources typically include hydro, geothermal, wind, low-cost biomass, nuclear and solar generation

Generation by Gas out of Total Generation excluding Low-cost power generation	16182.49	11.62	16949.00	11.87	12794.41	8.51
Generation by Diesel out of Total Generation eexcluding Low-cost power generation	4688.04	3.37	3225.00	2.26	2364.11	1.57
Generation by lignite out of total generation excluding low - cost power generation	15375.106	11.04	17791	12.46	18078.66	12.02
Estimation of Baseline Emission Factor (tCO_2/MU)						
Simple Operating Margin						
Fuel 1 : Coal						
Avg. Calorific Value of Coal used (kcal/kg)		3828.6		3979.7		4069.4
Estimated Coal consumption (tons/yr)		47884000		52657000		53164000
Emission Factor for Coal-IPCC standard value (tonne CO2/TJ)		96.1		96.1		96.1
Oxidation Factor of Coal-IPCC standard value		1.0		1.0		1.0
COEF of Coal (tonneCO2/ton of coal)		1.54		1.60		1.64
Fuel 2 : Gas						
Avg. Efficiency of power generation with gas as a fuel, %		45		45		45
Avg. Calorific Value of Gas used (kcal/kg)		11942		11942		11942
Estimated Gas consumption (tons/yr)		2589727.91		2712395.09		2047524.63
Emission Factor for Gas- IPCC standard value(tonne CO2/TJ)		56.1		56.1		56.1
Oxidation Factor of Gas-IPCC standard value		1.0		1.0		1.0
COEF of Gas(tonneCO2/ton of gas)		2.805		2.805		2.805
Fuel 3 : Diesel						
Avg. Efficiency of power generation with diesel as a fuel, %		41.7		41.7		41.7
Avg. Calorific Value of Diesel used (kcal/kg)		9760		9760		10186
Estimated Diesel consumption (tons/yr)		990613.324		681463.026		478659.193
Emission Factor for Diesel-IPCC standard value (tonne CO2/TJ)		74.1		74.1		74.1
Oxidation Factor of Diesel-IPCC standard value		1.0		1.0		1.0
COEF of Diesel (tonneCO2/ton of diesel)		3.03		3.03		3.16
Fuel 4 : Lignite						
Avg. Efficiency of power generation with lignite as a fuel, %		25		25		25
Avg. Calorific Value of Lignite used (kcal/kg)		2400		2400		2400
Estimated lignite consumption (tons/yr)		22117730.6		25593094.8		26006905.7
Emission Factor for Lignite-IPCC standard value (tonne CO2/TJ)		101		101		101
Oxidation Factor of Lignite-IPCC standard value		1.0		1.0		1.0

COEF of Lignite (tonneCO2/ton of lignite)		1.01		1.01		1.01
EF (OM Simple, excluding imports from other grids), tCO2/MU		944.79		1033.56		1071.90
EF (OM Simple), tCO2/MU		944.79		1033.56		1071.90
Average EF (OM Simple), tCO2/MU						1016.75

Step 2 - Calculate the Build Margin emission factor ($EF_{BM,y}$)

The Build Margin emission factor ($EF_{BM,y}$) is calculated as the generation-weighted average emission factor (tCO_2/MU) of a sample of power plants. The methodology suggests the project proponent to choose one of the two options available to calculate the Build Margin emission factor $EF_{BM,y}$

Option A:

Calculate the Build Margin emission factor $EF_{BM,y}$ *ex ante* based on the most recent information available on plants already built for sample group *m* at the time of PDD submission. The sample group *m* consists of either:

(a) The five power plants that have been built most recently, or
(b) The power plants capacity additions in the electricity system that comprise 20% of the system generation (in MU) and that have been built most recently.

Project participants should use from these two options that sample group that comprises the larger annual generation.

Option B:

For the first crediting period, the Build Margin emission factor $EF_{BM,y}$ must be updated annually ex post for the year in which actual project generation and associated emissions reductions occur. For subsequent crediting periods, $EF_{BM,y}$ should be calculated ex-ante, as described in Option 1 above. The sample group m consists of either

(a) the five power plants that have been built most recently, or
(b) the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MU) and that have been built most recently.

Project participants should use from these two options that sample group that comprises the larger annual generation.

APCL has adopted the Option A, which requires the project participant to calculate the Build Margin emission factor $EF_{BM,y}$ ex ante based on the most recent information available on plants already built for sample group m at the time of PDD submission. The sample group m should consist of either:

(a) the five power plants that have been built most recently, or
(b) the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MU) and that have been built most recently.

Project participants are required to use from these two options that sample group that comprises the larger annual generation. As per the baseline information data the option (b) comprises the larger annual generation. Therefore for the APCL project activity the sample group m consists of (b) the power plants capacity additions in the electricity system that comprise 20% of the system generation (in MU) and that have been built most recently. Power plant capacity additions registered as CDM project activities are excluded from the sample group.

The following Table 3 presents the key information and data used to determine the Simple BM emission factor:

Table 3: Key information and data used to determine simple BM emission factor		
Considering 20% of Gross Generation		
Sector	2004-05	%
Thermal Coal Based-State	1554.00	5.15
Thermal Coal Based-Central	7296.00	24.20
IPP-Coal Based	0	0.00
Lignite based power plant	4668	15.48
IPP-Gas (Naphtha) Based	8520	28.26
IPP-Diesel Based	422.32	1.40
Hydro-State	2200.70	7.30
Nuclear Based-Central	0.00	0.00
IPP-Co-Generation + biomass	3493.40	11.59
IPP-Wind	2000	6.63
Total	30154	100.00
Generation by Coal out of Total Generation	8850.00	29.35
Generation by Gas out of Total Generation	8520.06	28.26
Generation by Diesel out of Total Generation	422.32	1.40
Generation by lignite out of Total Generation	4668	15.48
Built Margin		
Fuel 1 : Coal		
Avg. efficiency of power generation with coal as a fuel, %		32.5
Avg. calorific value of coal used, kcal/kg		4069.4
Estimated coal consumption, tons/yr		5752500.0
Emission factor for Coal (IPCC),tonne CO2/TJ		96.1
Oxidation factor of coal (IPCC standard value)		1.0
COEF of coal (tonneCO2/ton of coal)		1.637

Fuel 2 : Gas		
Avg. Efficiency of power generation with gas as a fuel, %		45
Avg. Calorific Value of Gas used (TJ/Million M3)		37.98
Estimated Gas consumption (Million M3/yr)		1794.64
Emission Factor for Gas- IPCC standard value(tonne CO2/TJ)		56.10
Oxidation Factor of Gas-IPCC standard value		1
COEF of Gas(tonneCO2/Million M3 of gas)		2130.68
Fuel 3 : Diesel		
Avg. efficiency of power generation with diesel as a fuel, %		41.7
Avg. calorific value of diesel used, kcal/kg		10348
Estimated diesel consumption, tons/yr		84168.1
Emission factor for Diesel (as per standard IPCC value)		74.07
Oxidation factor of Diesel (IPCC standard value)		1.0
COEF of diesel tonneCO2/ton of diesel		3.21
Fuel 4 : Lignite		
Avg. efficiency of power generation with lignite as a fuel, %		25
Avg. calorific value of lignite used, kcal/kg		2683
Estimated lignite consumption, tons/yr		5985395
Emission factor for lignite (as per standard IPCC value)		101
Oxidation factor of lignite (IPCC standard value)		1
COEF of lignite tonneCO2/ton of lignite		1.13
EF (BM , excluding imports) (tCO2/MU)		673.3
EF (BM), tCO2/MU		673.3

Step 3 - Calculate the Combined Margin ($EF_{CM,, y}$)

The combined Margin $EF_{CM,y}$ is calculated as the weighted average of the Operating Margin emission factor ($EF_{OM,simple}$) and the Build Margin emission factor ($EF_{BM,y}$), where the weights w_{OM} and w_{BM}, by default, are 50% (i.e., $w_{OM} = w_{BM} = 0.5$), and $EF_{OM,y}$ and $EF_{BM,y}$ are calculated as described in Steps 1 and 2 above and are expressed in tCO_2/MU.

The most recent 3-years average of the Simple OM and the BM of the base year i.e. 2004-2005 are considered. This is presented in the table 4 below.

Table 4: Data used for Baseline Emission Factor

Parameters	Values (ton of CO_2/MU)	Remarks
Simple OM, $EF_{OM,simple}$	1016.75	Average of most recent 3-years values
BM, $EF_{BM,y}$	673.3	Value of the base year i.e. 2004-2005
Combined Margin, $EF_{CM,y}$	845.0	

OPTION 3: BASELINE EMISSION FACTOR OF THE TECHNOLOGY IDENTIFIED

Emission Factor(IPCC) of the fuel (Coal) for most likely baseline scenario tonne CO_2 /ton of coal	96.1
Avg. efficiency of power generation with coal as a fuel, %	33
EF (Baseline Technology) (tonne CO_2/MU)	1048

The lowest baseline emission factor arrived out of three above mentioned options i.e Built Margin is selected for the project activity.

Annex 4

MONITORING INFORMATION

As mentioned in section B.7.

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ENCLOSURE – I

Leakage Emission Calculation

Emission factor calculation for upstream fugitive methane emissions occurring in the absence of the project activity		
Estimated Quantity of coal combusted in plants included in build margin	11737895	tonnes/year
Fugitive methane emission factor for coal production (surface mining)	0.8	t CH_4/ kt coal
Total fugitive emission from coal production	197196.6332	tonne CO_2/year
Estimated Quantity of gas combusted in plants included in build margin	1795	million m^3/year
Average calorific value of gas used	38	TJ/ million m^3
Total energy content of the gas used	68.16	PJ
Fugitive methane emission factor for NG consumption	160.00	t CH_4/ PJ
Total fugitive emission from gas	229019	tonne CO_2/year
Estimated Quantity of oil combusted in plants included in build margin	84168	tonne/year
Average calorific value of oil used	10348	Kcal/kg
Total energy content of the oil used	3.66	PJ
Fugitive methane emission factor for oil consumption	4.1	tCH4/PJ
Total fugitive emission from oil	315	
Net power generation in the BM	**30075**	**MU**
Combined fugitive emission factor	14.18	tonne CO_2/MU

1	**Fugitive Methane Emission**		
1 a)	Fugitive Methane Emission from NG consumption		
	Quantity of natural gas combusted in the project plant per year	181350000	SCM/year
	Average Net Calorific Value of the natural gas combusted	9320	Kcal/ SCM
	Total energy content of the gas used	7	PJ
	Emission factor for fugitive emission for NG	160	t CH_4/PJ
	Fugitive Methane Emission from NG consumption	23852	t CO_2/e
1 b)	Fugitive emission from fossil fuel in absence of the		

	project		
	Electricity generation from project during a year	919	MU
	Combined fugitive emission factor (coal & gas)	**14.18**	t CO_2/year
	Total fugitive emission from fossil fuels in absence of the project	13039	
	Net leakage attributable to the project activity	10813	t CO_2/year
	Effective leakage	**10813**	t CO_2/year

Baseline and Project emissions		
Total power generation, million units	919	Million units
Net units exported to Southern grid, million units	874	Million units
Avg. calorific value of gas used,	9320	kcal/SCM
Gas consumption in the Plant (for 12 months)	181350000	SCM
Emission factor for gas (as per standard 2006 IPCC value)	56.1	tCO2/TJ
Oxidation factor of gas	1.0	
COEF	0.002	tCO_2/kg
EF (NG)	430.987	tCO_2/million units
Estimated emission factor of grid (BM)	673.3	tCO_2/million units
Annual baseline emission reduction	588215	ton CO2
Annual project activity emission	396249	ton CO2
Leakage	10813	ton CO_2
Net estimated annual emission reduction	181153	CER

Summary:

Year	**Baseline emissions, tCO2e**	**Project Emission, tCO2e**	**Leakage, tCO2e**	**Emission Reduction, tCO2e**
2006	588215	396249	10813	181153
2007	588215	396249	10813	181153
2008	588215	396249	10813	181153
2009	588215	396249	10813	181153
2010	588215	396249	10813	181153
2011	588215	396249	10813	181153
2012	588215	396249	10813	181153
2013	588215	396249	10813	181153
2014	588215	396249	10813	181153
2015	588215	396249	10813	181153
Total (ton CO2 equivalent)				**1811530**