PRE-FEASIBILITY REPORT
ON

STUDY FOR GAS BASED POWER PROJECT AT BELGAUM IN KARNATAKA

Submitted to

INFRASTRUCTURE DEVELOPMENT DEPARTMENT,
GOVT OF KARANATAKA

By

KSIIDC-IL&FS Project Development Company Limited (KIPDC)

Khanija Bhavan, 4th Floor, East Wing,
#49, Race Course Road, Bangalore – 560 001

April 22nd, 2010

Table of Contents

1. Introduction

The development of the power sector in the country since independence has been predominantly through the State Electricity Boards. In order to supplement the efforts of the States in accelerating power development and to enable the optimum utilisation of energy resources, the Union Government has permitted private participation in the power sector.

With the rapid industrialisation, successful rural electrification and large-scale use of electricity for the irrigation purpose, the demand for electricity has registered a significant growth. Also, it is expected that the on-going liberalisation of the country's economic policy would accelerate the industrial growth, which would further increase the demand for power. Although several new power projects have been identified with a view to bridge the gap between the demand and availability, only a few could be taken up for implementation due to financial and other constraints. This would result in large shortfall in the availability of both peak power (capacity required: 8,826 MW) and energy (units required: 53,540 MU) in the state of Karnataka as of 2010-2011 as per 17th Electric Power Survey carried out by Central Electricity Authority (CEA). The present demand for electrical power continues to grow and will continue to outstrip the available and planned generation capacity leading to chronic shortage of available power and energy in the future years.

Infrastructure Development Department (IDD), Government of Karnataka is the Infrastructure arm of **Government of Karnataka (GoK)** with the primary objective of facilitating development of infrastructure projects across Karnataka. IDD on behalf of Government of Karnataka has entered into a Gas Cooperation Agreement with Gas Authority of India Ltd.(GAIL) on 29.04.2009 for the development of natural gas infrastructure and city gas distribution network, to develop the use of eco-friendly fuels, especially Natural Gas/CNG/PNG/R-LNG and to promote a Joint Venture (JV) for domestic, industrial and transport sectors in the state of Karnataka.

Under the Agreement, GAIL will lay two gas pipelines in the state from Dabhol to Bangalore and Kochi to Bangalore and it is proposed to put up four gas-based power stations of 2000 MW capacity each along the gas pipeline corridor to be located at Belgaum, Gadag, Davangere and Tumkur districts.

In order to assess if these projects would be prima facie feasible for development at the said locations, IDD decided to engage KSIIDC-IL&FS Project Development Company Limited (KIPDC) for conducting Pre-feasibility study for the identified project at Belgaum. KIPDC along with the officials of M/s. Power Company of Karnataka Limited (PCKL) and M/s. GAIL Ltd. made site visits to assess the suitability of the identified sites based on the various infrastructure parameters required for the project.

This report highlights the details of the proposed sites along with the availability of the requisite infrastructure like availability of fuel and water, evacuation of power etc., Technical features of the main plant equipment, environmental aspects, estimates of project financials and issues pertaining to the Project.

2. Need for the Project

2.1 Industry Overview

Over the last 10 years, the total capacity addition in the power sector slowed down as neither the Private Sector nor the Electricity Boards added adequate new capacity while growth in demand was sustained. The Government of India took in view the various reasons for lack of interest on the part of the Private Sector and after discussions with various stake holders such as Industrial Consumers, Farmers and the Power Producers revised the Electricity Act to bring in a competitive atmosphere & to promote private participation in power field.

The Electricity Act- 2003

The Electricity Act – 2003 passed by the Parliament promises to usher in sweeping changes. The Act seeks to provide a legal framework for enabling reforms and restructuring of the Power Sector. It has simplified administrative procedure by integrating the Indian Electricity Act, 1910, the Electricity (Supply) Act, 1948 and the Electricity Regulatory Commissions Act, 1998 into a single Act.

The Electricity Act, 2003 is based on the principle of promoting competition, protecting consumers' interests and providing power to all. The salient features of the act are:-

- Delicensing of power generation.
- Liberalization in captive power policy
- Open access to transmission and distribution network.
- Stringent penalties for power thefts.
- Transparent subsidy management
- Constitution of Appellate Tribunal
- Thrust on rural electrification

The Bill seeks to consolidate the laws relating to generation, transmission, distribution, trading and use of electricity; take all measures that are conducive to the development of the sector including rationalization of electricity tariff, ensuring transparent policies regarding subsidies; address environmental concerns, and empower the existing power sector regulators and create new capacities.

2.2 Perspective of Power Development (2002- 2020)

2.2.1 Power Development Scenario up to end 11th Plan (2002-12)

As per the "5th National Power Plan (2002-2012)" prepared by Central Electricity Authority (CEA), a need based installed capacity to the order of 2,12,000 MW is required by the end of 11th Plan based on demand projections of the 16th Electric Power Survey and a system reliability level of Loss of Load Probability (LOLP) less than 1% for the country. The primary resources for Electric Power Generation are water, fossil fuel (coal, lignite, oil & natural gas) and nuclear energy. They would continue to serve as major resources for electric power generation in the long run, though various forms of renewable source, such as wind, bio-mass, tides etc., will also contribute.

For 11th Plan ending in March 2012, CEA has identified a capacity addition of 78,700 MW, comprising of 15,627 MW Hydro, 59,693 MW thermal, and 3,380 MW of Nuclear. The 11th Plan program is comparatively large so as to provide not only for normal growth during the 11th Plan period, but also to compensate for the short fall in the capacity addition during 10th Plan period.

2.2.2 Power Development Scenario Beyond 11th Plan (2012-2020)

The Indian Power System requirement had been assessed to need a hydro-power and thermal/nuclear power-mix in the ratio of 40:60 for flexibility in system operation depending on typical load pattern. To achieve this mix and to accelerate the hydropower development, 50,000 MW hydro electric initiative was launched by the Government of India on May 24, 2003. Hydro Wing of CEA, has identified a hydro capacity of 35,523 MW for yielding benefits during the 12th Plan period (2012-2017). These schemes have been identified based on their present status as available with CEA.

Nuclear Power Corporation has planned to add nuclear power projects aggregating to 10,000 MW for giving benefits between 2012 and 2020.

A preliminary study has been carried out by CEA to estimate the capacity addition between 2012 and 2020 extending the demand projections of 17th Electric Power Survey.

The optimal plan of the study has indicated a capacity addition of 1,35,000 MW during this period comprising of 35,500 MW hydro, 10,000 MW Nuclear and 89,500 MW Thermal (including 6500 MW gas based plants). The Thermal-based capacity required shall be about 83,000 MW during the period 2012-2020. Any shortfall in achieving hydro-capacity addition would also have to be made good by additional thermal based projects.

For the 10th plan, ending on March 31, 2007, the capacity addition in the country is substantially falling short against the target of 41,110 MW. The target of 11th plan is 78,700 MW, which is already very high.

Thus In spite of few of the Private Power Producers announcing plans for setting up the new capacities, there remains a wide gap to be bridged towards achieving the envisaged target. Keeping in view the huge power generation capacity required to be added during 11th and 12th Plan periods, an urgent need is felt for large scale thermal power development.

Installed Capacity

The details of the installed capacity in India as on 31.12.2009 is as provided in Table 2.1 below:

Sector	Hydro	Thermal				Nuclear	R.E.S. (MNRE)	Total
		Coal	Gas	Diesel	Total			
STATE	27087	44054	4046	603	48703	0	2624	**78414**
PRIVATE	1233	7126	6307	597	14031	0	12602	**27866**
CENTRAL	8565	30425	6702	0	37127	4120	0	**49813**
TOTAL	**36885**	**81606**	**17055**	**1200**	**99861**	**4120**	**15226**	**156093**

Source: Central Electricity Authority (Planning Wing)

Table 2.1: Installed capacity in India as on 31.12.2009

Actual Power Supply Position

The demand and supply gap for various years is tabulated in Table 2.2 below:

Period	Peak Demand (MW)	Peak Met (MW)	Peak eficit/ Surplus (MW)	Peak Deficit/ Surplus (%)	Energy Requi-rment (MU)	Energy Avail-ability (MU)	Energy Deficit/ Surplus (MU)	Energy Deficit/ Surplus (%)
9TH PLAN END	78441	69189	-9252	-11.8	522537	483350	-39187	-7.5
2002-03	81492	71547	-9945	-12.2	545983	497890	-48093	-8.8
2003-04	84574	75066	-9508	-11.2	559264	519398	-39866	-7.1
2004-05	87906	77652	-10254	-11.7	591373	548115	-43258	-7.3
2005-06	93255	81792	-11643	-12.3	631757	578819	-52938	-8.4
2006-07	100715	86818	-13897	-13.8	690587	624495	-66092	-9.6
2007-08	108866	90793	-18073	-16.6	739345	666007	-73338	-9.9
2008-09	109809	96685	-13124	-12	774324	689021	-85303	-11
Apr-Dec,'09	116281	101609	-14672	-12.6	617554	557138	-60416	-9.8

Source: Central Electricity Authority (Planning Wing)

Table 2.2: Demand-Supply scenario in India as on 31.12.2009

2.3 Karnataka Power Sector Scenario

Introduction

The development of the power sector in the country since independence has been predominantly through the State Electricity Boards. In order to supplement the efforts of the States in accelerating power development and to enable the optimum utilisation of energy resources, the Union Government has permitted private participation in the power sector.

With the rapid industrialization, successful rural electrification and large-scale use of electricity for the irrigation purpose, the demand for electricity has registered a significant growth. Also, it is expected that the on-going liberalization of the country's economic policy would accelerate the industrial growth, which would further increase the demand for power. Although several new power projects have been identified with a view to bridge the gap between the demand and availability, only a few could be taken up for implementation due to financial and other constraints. This would result in large shortfall in the availability of both peak power (capacity required: **8,338 MW**) and energy (units required: **50,417 MU)** in the state of Karnataka as of 2010-2011 as per 17th Electric Power Survey carried out by

Central Electricity Authority (CEA). The present demand for electrical power continues to grow and will continue to outstrip the available and planned generation capacity leading to chronic shortage of available power and energy in the future years.

State Economy

The Gross State Domestic Product for Karnataka in 2006-07 was Rs. 1,94,008 crore (at current prices) as against Rs. 37,18,000 crore for India, which makes it 5.2% of the country's GDP. Karnataka has had moderate growth rates in its State income. In the period 1999-2006, Karnataka had a GSDP growth rate of 5.9% making it fourth amongst compared States and lesser than India's GDP growth of 6.5%. The State's real income growth, which struggled to cross beyond 4% till the early 1990s has now reached nearly 6%. A year wise GSDP growth comparison for India and various other States shown is Fig. 2.1 exhibits that Karnataka has shown healthy growth trends in the past.

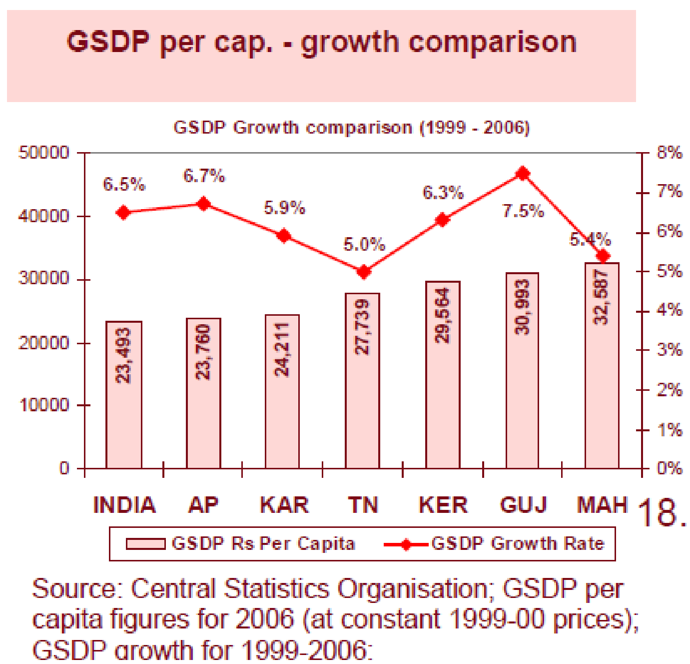
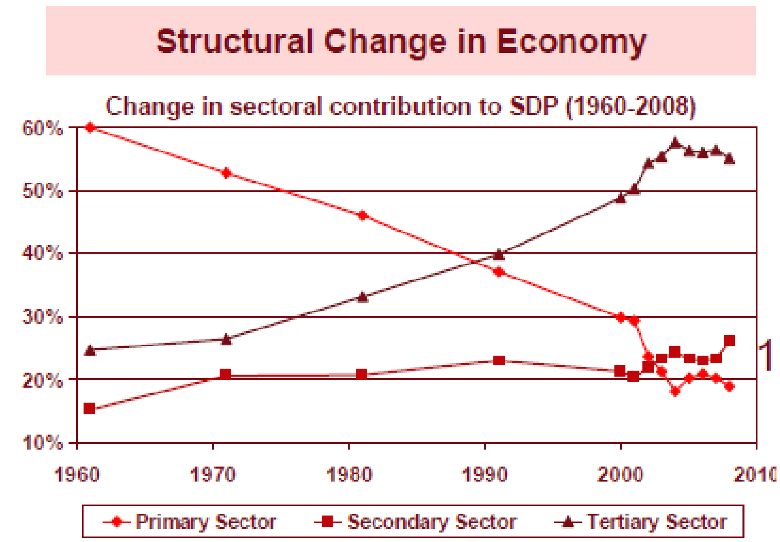


Fig 2.1: GSDP per capita – Growth Comparison

As shown in Fig. 2.2, the character of the State's economy has changed drastically over the years. When the State was formed in 1956, its economy was predominantly agrarian, but this has now altered. The primary sector, which contributed about 60% of the GSDP in 1960- 61 comprised only about 18.9% in 2006-07. In the same period, the share of secondary sector increased from 15.2% to 26%. The share of the tertiary sector has more than doubled from 24.8% to 55.1%. The service sector boom since the 1990s has boosted the State's economic growth. The manufacturing sector which lagged behind for some time has grown well, though in relative terms, it has remained steady. Among sub-sectors of the economy during the 10th Plan, agriculture continues to be the largest sub-sector in terms of contribution, but at 1.4%, it had the lowest growth rate. Manufacturing has shown the 2nd highest growth of 9.4% and is showing resurgence.



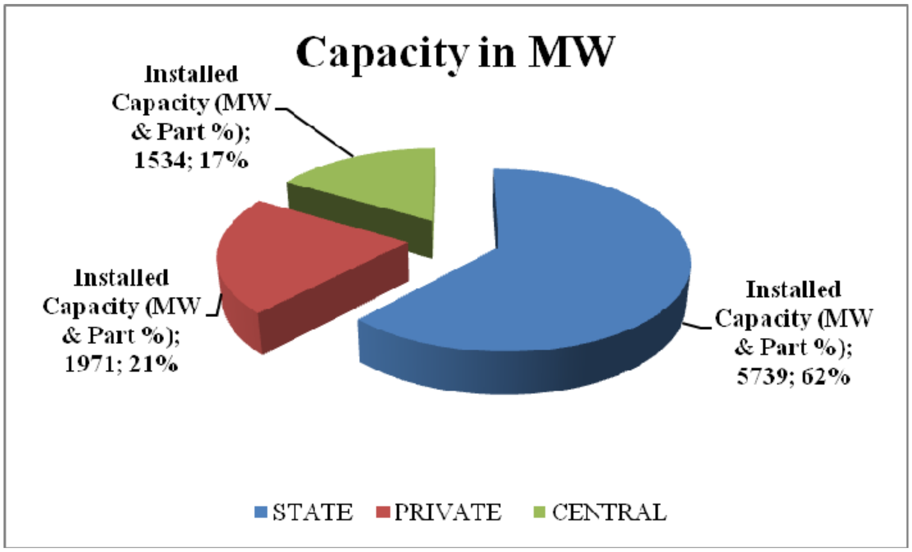
Source: Directorate of Economics and Statistics, GoK

Fig 2.2: Structural Change in Economy

Sustainability and acceleration of Karnataka's economic growth critically hinges on the availability of adequate and good quality infrastructure facilities. Though the State's physical infrastructure is fairly extensive, it has failed to keep pace with rapidly rising demand resulting in frequent and acute demand-supply gaps. The capacity and quality of the State's infrastructure is certainly a matter of concern. With changing structural composition of the economy and anticipated labour movement towards more productive employment, the demand for quality infrastructure is expected to increase significantly, on both absolute and per capita basis. This calls for a larger, coordinated transformational approach to infrastructure planning and implementation. While the Government's investment for infrastructure development is inescapable, the PPP route also needs to be encouraged. Along with supplementing scarce public resources, it creates a competitive environment and thus improves efficiencies.

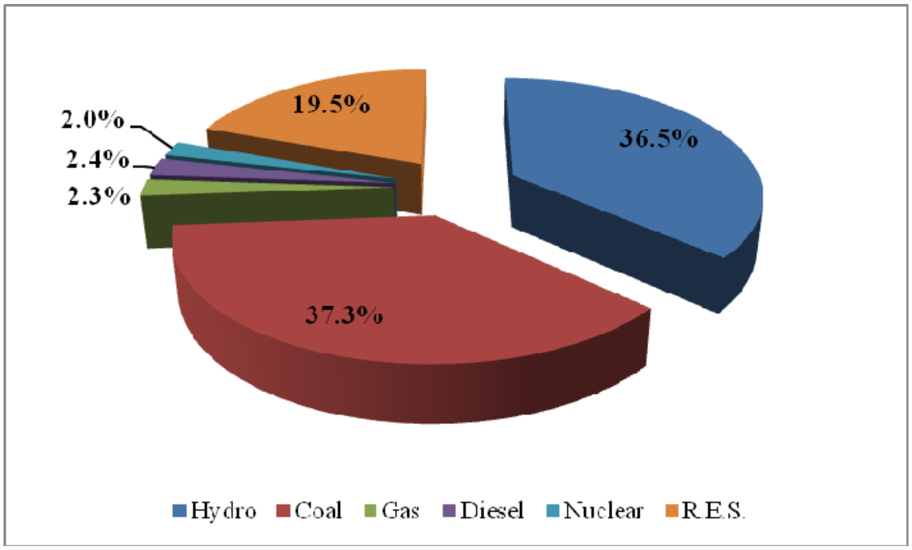
Installed Capacity

The installed capacity of the state as of 31st December, 09' is 9,249 MW. The below Figures 2.3 & 2.4 shows the sector wise and the fuel wise distribution of the installed capacity



Source: Central Electricuty Authority

Fig 2.3: Distribution of Installed Capacity in Karnataka



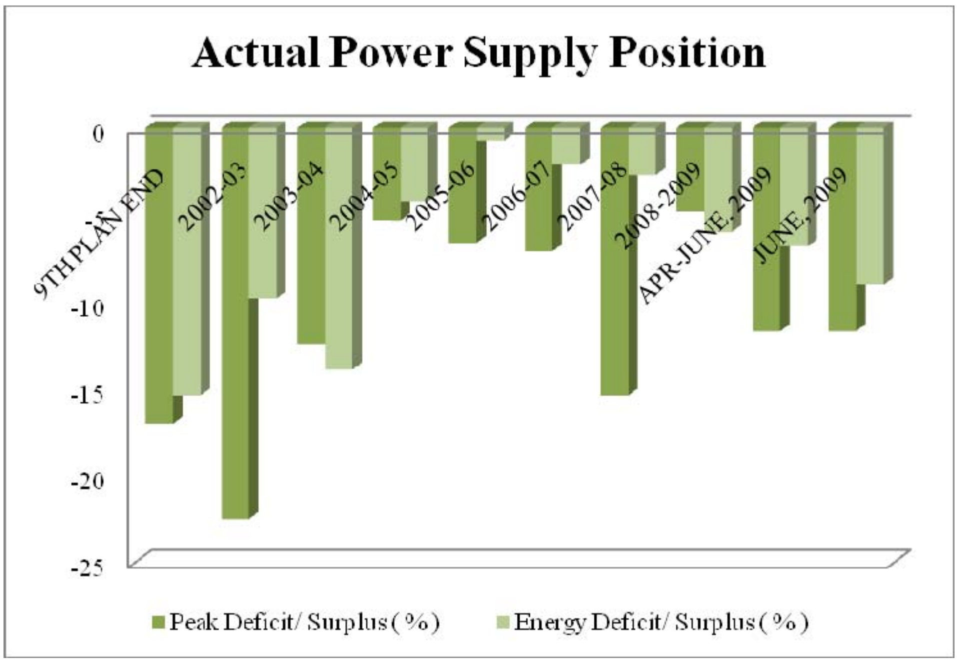
Source: Central Electricuty Authority

Fig 2.4: Source wise distribution of Installed Capacity in Karnataka

As seen above, the overdependence of the state on coal and hydro has been a major cause of shortage in the state as the state has no coal deposits and has to import the same from other states whereas the unpredictable monsoon rains makes it difficult to predict a sustainable power supply position.

Demand Supply Gap

The state has witnessed a consistent trend of peak power deficits and the energy deficits of the range of 11 % in the last few years as shown in Figure 2.5. With the state registering a healthy State Domestic Product (SDP) growth, the coming years are going to increase this gap only.



Source: Central Electricity Authority

Fig 2.5: Year wise Demand Supply gap

Transmission & Distribution Losses

With around 25 % AT&C losses for the year 2008-09, the distribution companies have to charge higher tariffs to remain sustainable.

YEAR WISE T&D LOSSES

2003-04 – 30.88 %

2004-05 – 29.44 %

2005-06 – 29.38 %

2006-07 – 29.68 %

2007-08 – 25.16 %

2008-09 – 24.03 %

Planned Vs. Actual Achieved Capacity Additions

Though the State government has been setting higher targets each year, the achievement has been far from satisfactory. The below Table 2.3 shows the gap between the requirement capacity and the achieved capacity for the state.

YEAR	PEAK		ENERGY	
	Requirement as per 17th EPS	Actual Achieved	Requirement as Per 17th EPS	Actual Achieved
2004-05	5928	5612	35157	33110
2005-06	6275	5558	37334	34641
2006-07	6642	5959	39646	40709
2007-08	7031	5715	42101	42934
2008-09	7442	6548	44709	44122
2009-10	7877	6352	47477	
2010-11	8338		50417	
2011-12	8826		53540	

Source: Central Electricity Authority

Table 2.3: Planned Vs Achieved Peak & Energy demand of the State

Conclusion

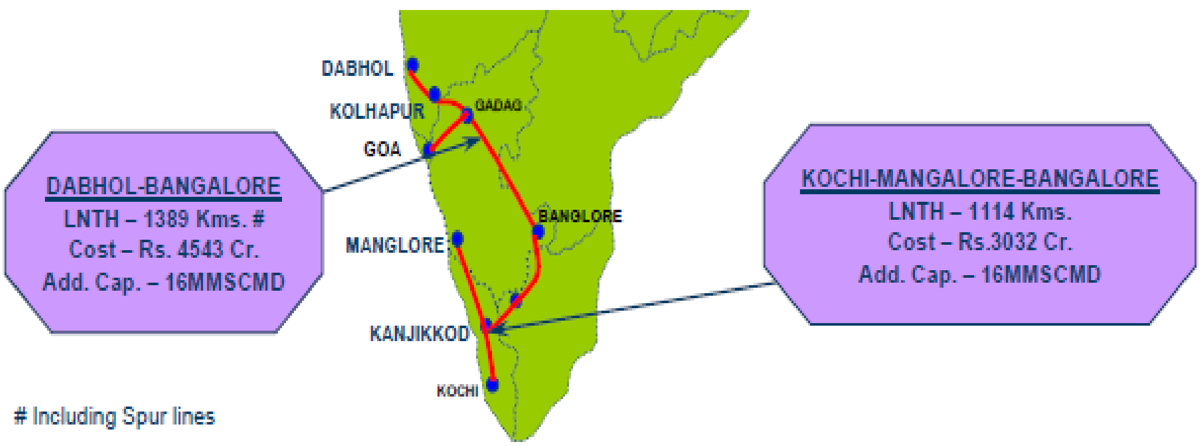
Considering the future expected healthy growth rates and the change in the sector wise contribution to the State Economy with both manufacturing as well as the service going to play a major role in the years to come, the development of energy infrastructure will hold the key to a sustainable growth in the future. This is also inline with the vision at the National level as described in the earlier section.

With the existing infrastructure clearly lagging behind the requirement, the development of the said power project will go a long way in securing both current as well as future energy requirements of the state. Hence, the project is justified.

3. Project Concept

3.1 Description of the Project

GAIL has proposed to implement 30 inch diameter, 730 kilometer long Dabhol – Banglore pipeline that is being designed to carry 16 mmscmd of gas and it has signed an MoU with State Govt. for putting up this pipeline. As shown in Figure 3.1, the inception point of the proposed pipeline is from R-LNG Terminal of Ratnagiri Gas and Power Private Limited (RGPPL) at Dabhol in Maharashtra up to Bangalore.



Source: Gas Authority of India Limited (GAIL)

Fig 3.1: Proposed Dabhol – Bangalore Gas Pipeline Route

The pipeline is proposed to pass through Belgaum, Dharwad, Haveri, Davangere, Chitradurga, Tumkur and Bangalore districts of Karnataka. With this pipeline, natural gas can be supplied to industrial clusters in the state of Karnataka.

To utilize this opportunity and to tide over the power crises in the power starved state, Govt. of Karnataka is keen to develop 2000 MW capacity power plant at Belgaum that is located along the gas pipeline corridor.

To assess the feasibility of such projects at the said locations, IEDCL team along with the nodal officers of Power Company of Karnataka (PCKL) made site visits to two identified locations at Belgaum between 09th – 11th February.

3.2 Components of the Project

For a project size of 2000 MW as ascertained by Govt. of Karnataka, the important criterion for site selection that was adopted by KIPDC is as follows:

(i) Total land required for setting up the project facility shall be around 400 acres at a stretch without any encumbrance.

(ii) The project site shall be close to the water source. Around 40 cusecs of water quantity requirement was identified for the proposed capacity

(iii) The project site shall be near to the source of fuel i.e. gas pipeline. Around 9 mmscmd of natural gas requirement was identified for the proposed capacity

(iv) The project site to be suitable from feasibility of power evacuation point of view

(v) The project site shall require minimum displacement of habitation and away from the habitation area.

(vi) The project site to be closer to highway with hindrance free approach for transportation of heavy equipment.

(vii) The plateau of the project site shall be as flat as possible.

(viii) The project site shall be above flood level.

(ix) The project site shall be free from any environmental restriction like forest, Natural Park, wild life century etc.

Based on the above mentioned criteria, two site locations as identified by PCKL in Belgaum were studied and a summary of the same is given below:

3.3 Site Visit Summary

Site I: Gokak

Location

The site is located in North Karnataka near Lolasur Village, Gokal Taluk, Belgaum District. The nearest railway station is about 15 km at Ghataprabha and the nearest airport is about 150 Km at Hubli. The Longitude and Latitude are N 16^{o} 13'01.39" and E 74^{o} 48'51.4" respectively.

Land

Around 250 acres of the private land has been identified for the power plant. As shown in Figure 3.2 the topography of the land is partly flat and partly slopy with some portion as barren & wasteland while the rest used for the agricultural purpose with one season crop of sunflower & maize being grown.

Fig 3.2: Snapshot of the identified land at Lolasur near Gokak

Accessibility

The site is around 3-4 km from the State Highway – 44 (SH-44) and about 25-30 km from the National Highway – 4 (NH-4). The site is well connected by an approach road to the SH. The site can be easily approached and movement of plant equipments to site is not envisaged to be problematic.

Water

Ghataprabha river is identified as the water source for the project and it is proposed to draw from the water from the nearby Hidkal Dam that is approx. 25 km away from the proposed project site. Around 35-40 cusec of water availability needs to be assured from the Water Resource Department.

Fig 3.3: Photograph showing River Ghataprabha along with the Hidkal Dam on the backside

Power Evacuation

220 KV Ghataprabha sub-station belonging to Karnataka Power Transmission Corporation Limited is within 30 km of the Project site.

Fig 3.4: A snapshot of Ghataprabha Sub-station

Gas Grid

The nearest available Gas tapping from the proposed Dabhol- Bangalore gas pipeline being laid by M/s. GAIL is about 5-10 Km at Gokak. A spur line can be laid from this tap point to the project site.

Others

There is Wild Life Century known as Ghataprabha Sanctuary that is falling in the vicinity of the proposed site. Right now the identified land is falling within the radial distance of 10 Km from the boundary of the sanctuary. Also, the land being a private land with the land use pattern as agriculture, some Rehabilitation & Resettlement issues are expected.

Fig 3.5: A snapshot of Ghataprabha Bird-Sanctuary

Site II: Chillabhabi

Location

The site is located in Northern Karnataka near the Chillabhabi village, Hukkeri Taluk, Belgaum District. The nearest railway station is about 25-30 km at Ghataprabha and the nearest airport is about 150 Km at Hubli. The Longitude and Latitude are N 16^{o} 07’11.44” and E 74^{o} 39’11.37” respectively.

Land

Around 2600 acres of the Government land has been identified for the power plant. As shown in Fig. 3.6 & 3.7, the topography of the land is slightly uneven and major portion of it is a wasteland with very little R&R issue. A suitable area of about 400-500 acres needs to be identified from the available 2600 acres for the proposed power project.

Fig 3.6: Photograph of the available land

Fig 3.7: Photograph of the available land

Accessibility

The site is around 8-10 km from the National Highway – 4 (NH-4). There is an approach road available and the site can be easily accessed. Hence, the movement of plant equipments to site is not envisaged to be problematic.

Water

Ghataprabha River is identified as the water source for the project and it is proposed to draw from the water from the nearby Hidkal Dam that is approx. 5-10 km away from the proposed project site. Around 35-40 cusec of water availability needs to be assured from the Water Resource Department.

Fig 3.8: A snapshot of the backwaters of the Hidkal dam nearby the proposed site

Power Evacuation

220 KV Ghataprabha sub-station belonging to Karnataka Power Transmission Corporation Limited is within 30 km of the Project site.

Also as shown in Figure 3.9, 400 KV Narendra sub-station belonging to Power Grid Corporation of India Limited is about 110 km from the proposed Project site.

Fig 3.9: A snapshot of the Narendra Substation of PGCIL

Gas Grid

The nearest available Gas tapping from the proposed Dabhol- Bangalore gas pipeline being laid by M/s. GAIL is about 20 Km at Gokak. A spur line can be laid from this tap point to the project site.

Others

Ghataprabha Wildlife Sanctuary is located at about 15 km from the proposed project site. Considering the guidelines of Ministry of Environment & Forest (MoEF) of maintaining minimum 10 km distance from any nearby environmental spot, the proposed project is at a comfortable distance from the said sanctuary. However, it is recommended to get a confirmation from the State Forest Department regarding the distance while selecting the exact site area of about 400 acres to avoid any hurdles during the environmental clearance stage for the project.

Summary

A site visit summary is given below in Table 3.1:

Particulars	B1 Gokak	B2 Chillabhabi
Land Availability (acres)	250-300	2600
Land Ownership	Private	Government
Present land use	Agricultural	Wasteland
Distance from Water	25 km, Hidkal Dam	5-10 km, Hidkal Dam
Fuel source	5 Km	20 Km
Power Evacuation (400 kV)	30 km	30 km
Accessibility	25-30 km from NH – 4 2-3 km from SH-44	8-10 km from NH-4
Environmental considerations	Site within 10 km of Ghataprabha Wildlife Sanctuary	Nil
Population to be displaced	Few	Few
Issues	1. Land area 2. Land Terrain 3. Distance from the sanctuary	1. Land terrain is slightly uneven. Around 400 acres of flat land needs to be identified

Table 3.1: Tabular Summary of the details of the site visited for the proposed project

3.4 Observations & Recommendations

Based on the information collected from discussions with officials of different departments and agencies during the site visit, following observations and recommendations can be made:

A. Fuel Source & Quantity

As already mentioned the above mentioned power project is being planned on the basis of the Dabhol-Banglalore pipeline that is going to be implemented by M/s GAIL Ltd. It is understood from the representative of the company that the pipeline will be pumping both the domestic as well imported Liquefied Natural Gas (LNG) and a preliminary assessment of the future customers and their requirement have been carried out. Prima facie it is understood from the information made available, that only about 8-9 mmscmd of the fuel will be made available to the proposed power project. Considering the requirement of about the same quantity (8-9 mmscmd) of gas for a 2000 MW capacity power project, only a single project of the 2000 MW capacity can be considered based on the above pipeline. For planning of the same capacity projects at 4 different locations, other sources of fuel need to be identified. A confirmation regarding the allocation of the quantum of the gas (8-9 mmscmd) needs to be taken from M/s GAIL before further planning is carried out. Additionally, discussions regarding increasing the quantum of the gas can also be done with M/s GAIL for other projects.

B. Fuel Pricing

Presently, India has broadly two pricing regimes for natural gas – one applicable for production of National Oil Companies (NOCs) namely ONGC and OIL from their nomination fields called Administered Price Mechanism (APM) and second is market determined prices for gas produced by joint ventures/pvt. Companies under Production Sharing Contract (PSC) regime and for imported R-LNG.

The APM price excluding royalty and taxes is Rs. 3200 per thousand cubic metre for power, fertilizer, consumers covered under court orders and supplies of less than 0.05

mmscmd. For other consumers, the gas price excluding royalty and taxes is 20% higher at Rs. 3840 per thousand cubic meter. The Tariff Commission has recommended a producer price for APM gas at Rs. 3600 and Rs. 4040 per thousand cubic meter for the gas of ONGC and OIL respectively and the discussions are still ongoing on the subject matter.

The gas prices for gas sold by pvt./JV companies ranges between US$ 3.50 to US$ 5.70 per million british thermal unit (mmbtu). Recently, the Government has approved a Gas Price Formulae for KGD6 block of RIL-Niko which yields a gas price of US$ 4.20 per mmbtu at a crude price of US$ 60 per barrel. The R-LNG price under term contract from Qatar is US$ 3.86 per mmbtu. The spot prices for R-LNG have been even over US$ 10 per mmbtu.

It is expected that M/s GAIL Ltd., being the principal marketer for all of the above mentioned sources, will be supplying the natural gas by pooling various sources. Considering the fact that even in the case of domestic gas, the landed price of the gas will not be less than US$ 5/mmbtu (including gas transportation, marketing margin, taxes & duties) and after pooling the prices for the gas from various sources, three gas prices US$ 6.0 per mmbtu, US$ 6.5 per mmbtu and US$ 7.0 per mmbtu have been considered for this project.

C. Distance from the Sanctuary

As per the MoEF guidelines, minimum 10 km of distance needs to be maintained between any environmental sensitive spot and the power project. The first site identified at Gokak falls with in 10 km of Ghataprabha Wildlife Sanctuary. Considering this constraint, it is recommended not to further explore the feasibility of putting up the power project in this particular site.

Conclusion

Considering various aspects as mentioned above, prima facie the first site identified at Gokak does not looks suitable for putting up the project because of the near vicinity of wildlife sanctuary, sloppy terrain and inadequacy of land available.

However, the second site identified at Chillabhabi looks prima facie suitable for further exploring the possibility of putting up a power project. As already mentioned because of the uneven nature of the land it is advised to identify around 400-500 acres of land that is relatively flat in nature for the proposed project from the available 2600 acres of land.

3.5 Details of the Site further recommended for exploration

3.5.1 Site Location Details

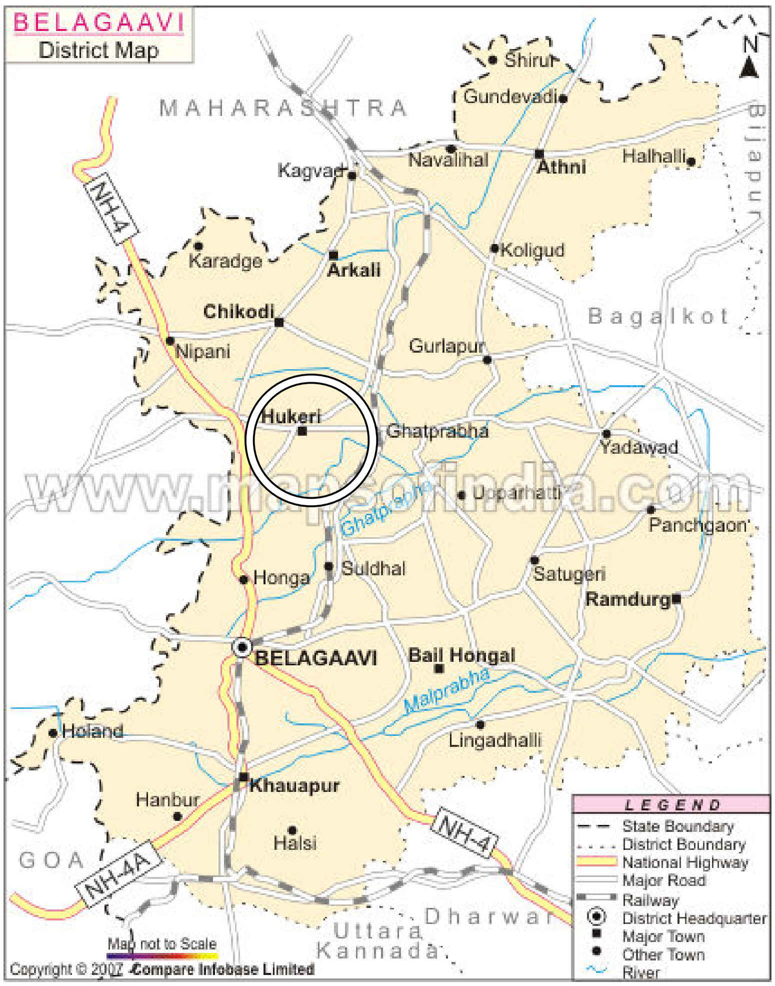
As shown in Figure 3.10, the site is located in Northern Karnataka near the Chillabhabi village, Hukkeri Taluk, Belgaum District. The nearest railway station is about 25-30 km at Ghataprabha and the nearest airport is about 150 Km at Hubli. The Longitude and Latitude are N 16^{o} 07'11.44" and E 74^{o} 39'11.37" respectively.

Source: www.mapsofindia.com

Fig 3.10: State Map indicating the location of the Proposed Project

1. Location

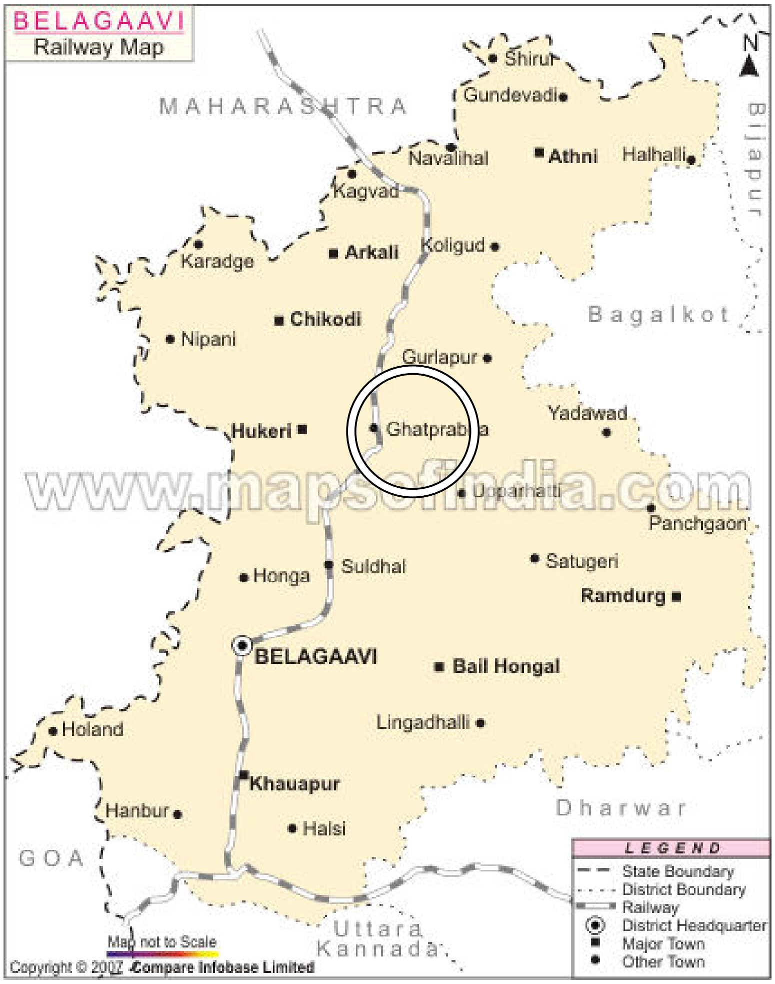
Village / City	:	Chillabhabi village, Hukkeri Taluk,
District	:	Belgaum
State	:	Karnataka, India



Source: www.mapsofindia.com

Fig 3.11: District Map indicating the location of the Proposed Project

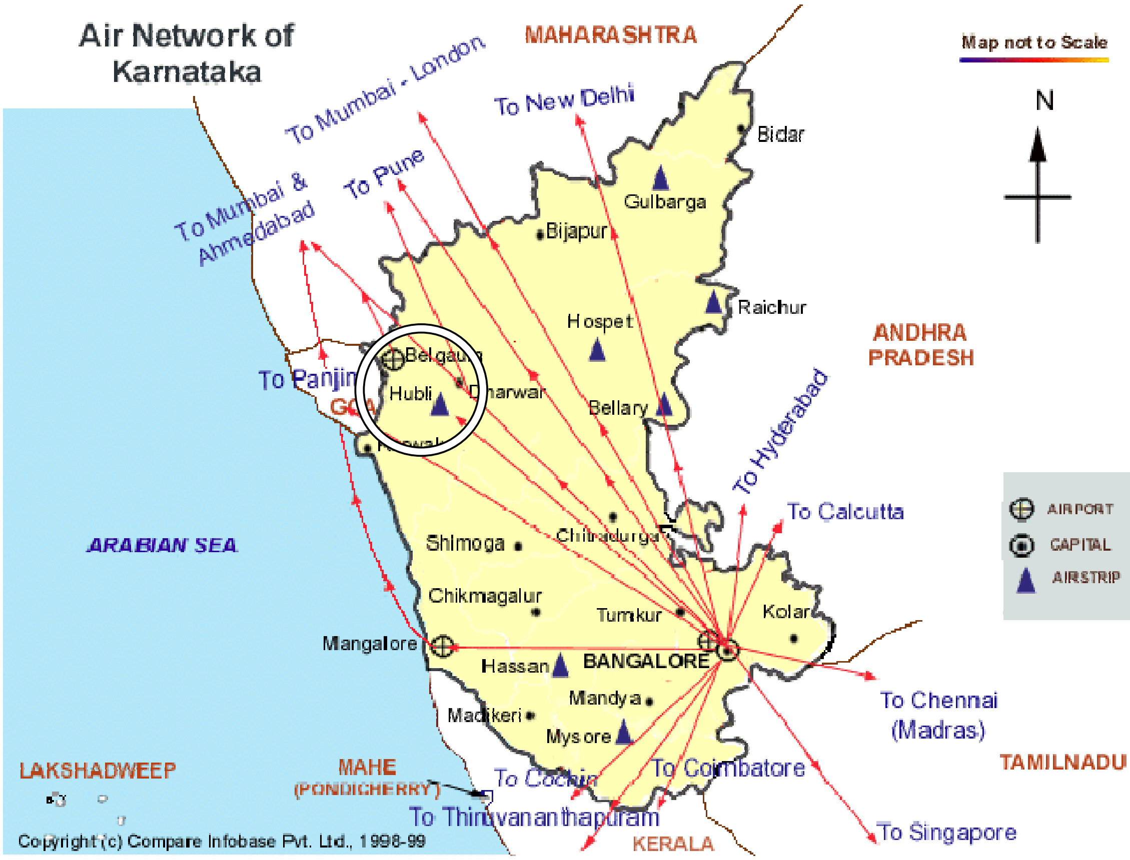
2. Nearest Railway Station : 25-30 km at Ghataprabha



Source: www.mapsofindia.com

Fig 3.12: District Map indicating the location of the nearest rail station

3. Nearest Airport: Hubli (150 km from the project site)



Source: www.mapsofindia.com

Fig 3.13: State Map indicating the location of the nearest airports

4. Nearest Harbour : Chennai/Mangalore/Goa port

Source: www.mapsofindia.com

Fig 3.14: Map indicating the location of the nearest seaports

3.5.2 Land Location on Google Imagery

Around 2600 acres of the Government land has been identified for the power plant. The topography of the land is slightly uneven and major portion of it is a wasteland with very little R&R issue. A suitable area of about 400-500 acres needs to be identified from the available 2600 acres for the proposed power project.

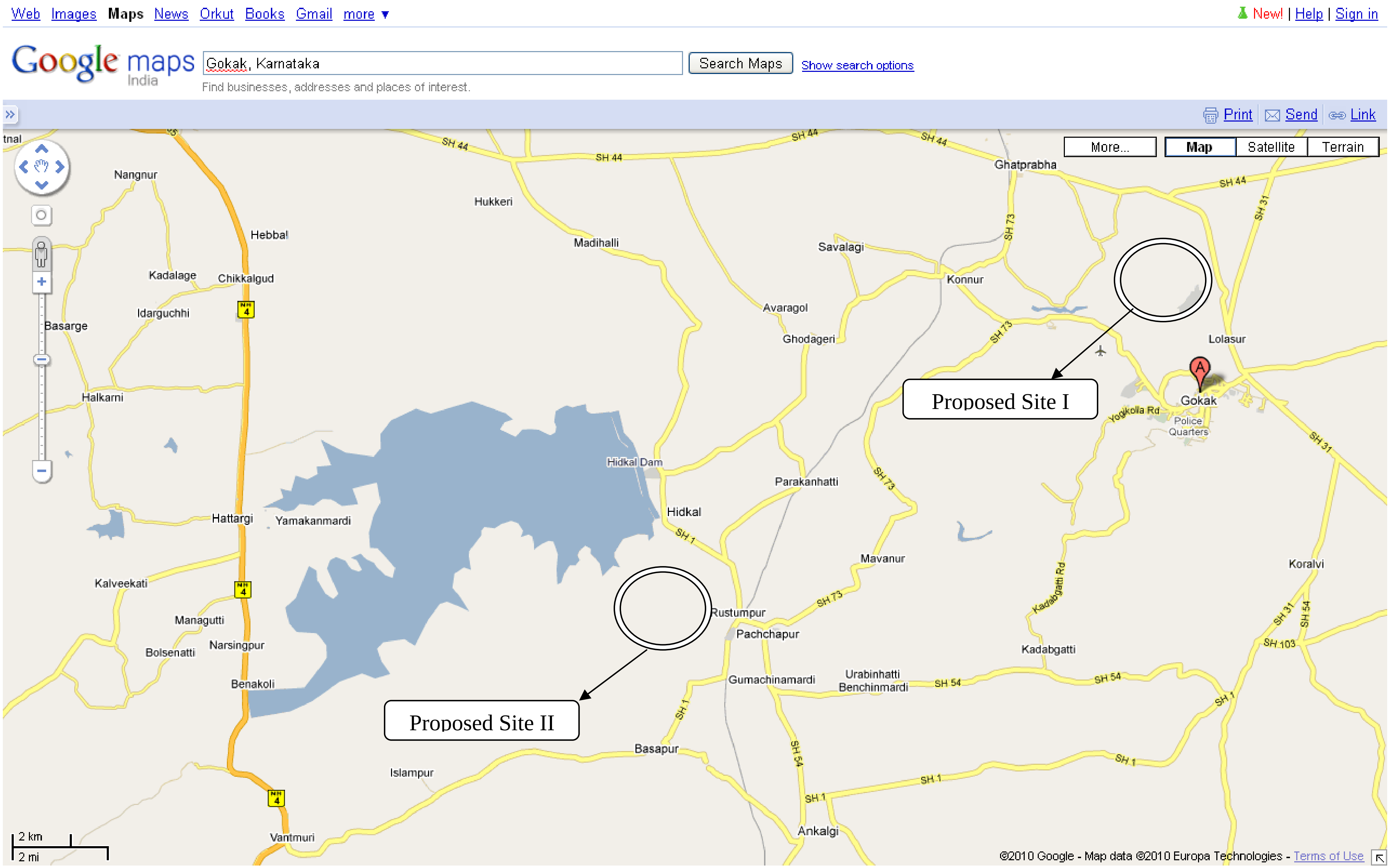


Figure 3.15: Location map showing the proposed project site

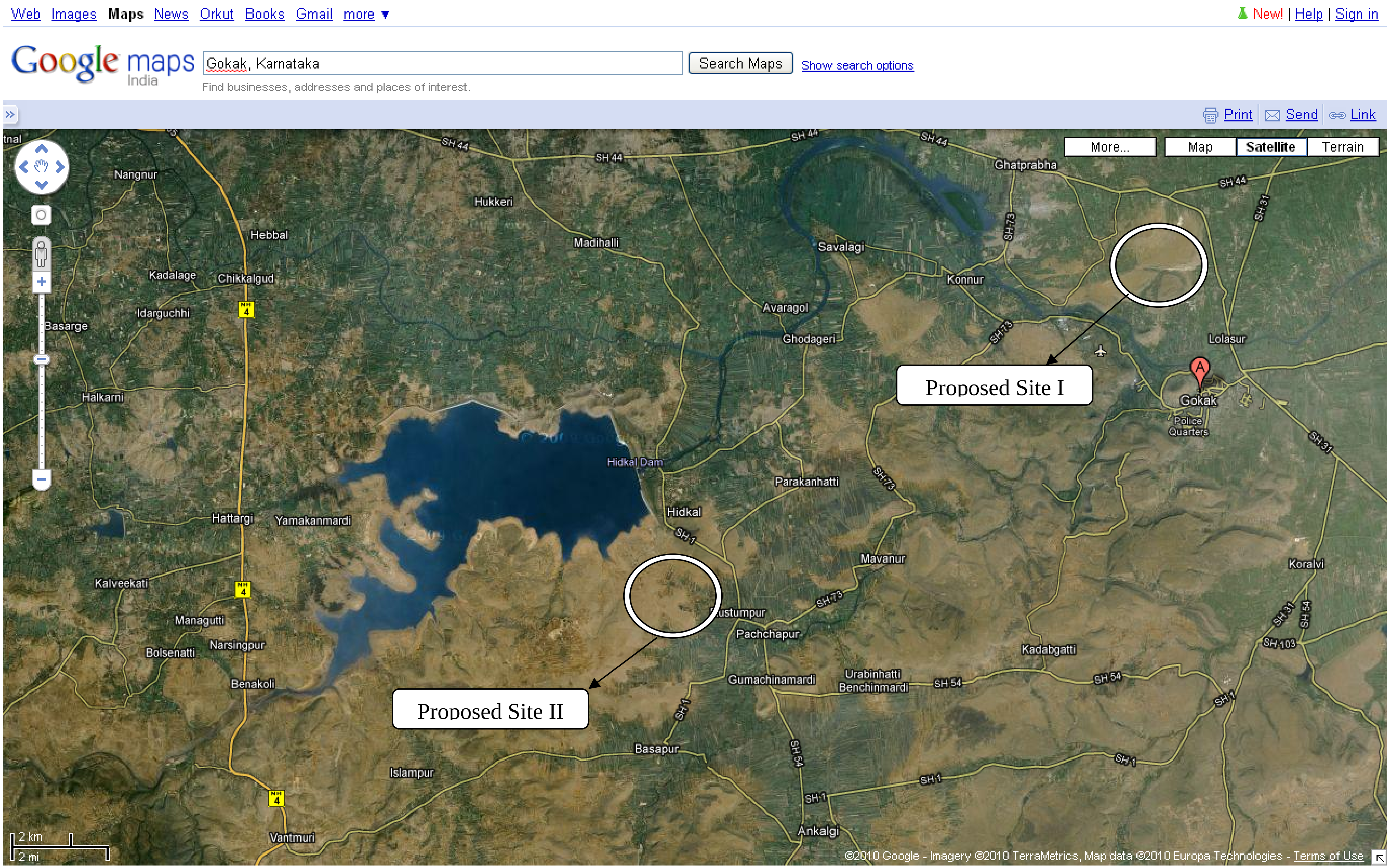


Figure 3.16: Location map showing the proposed project site

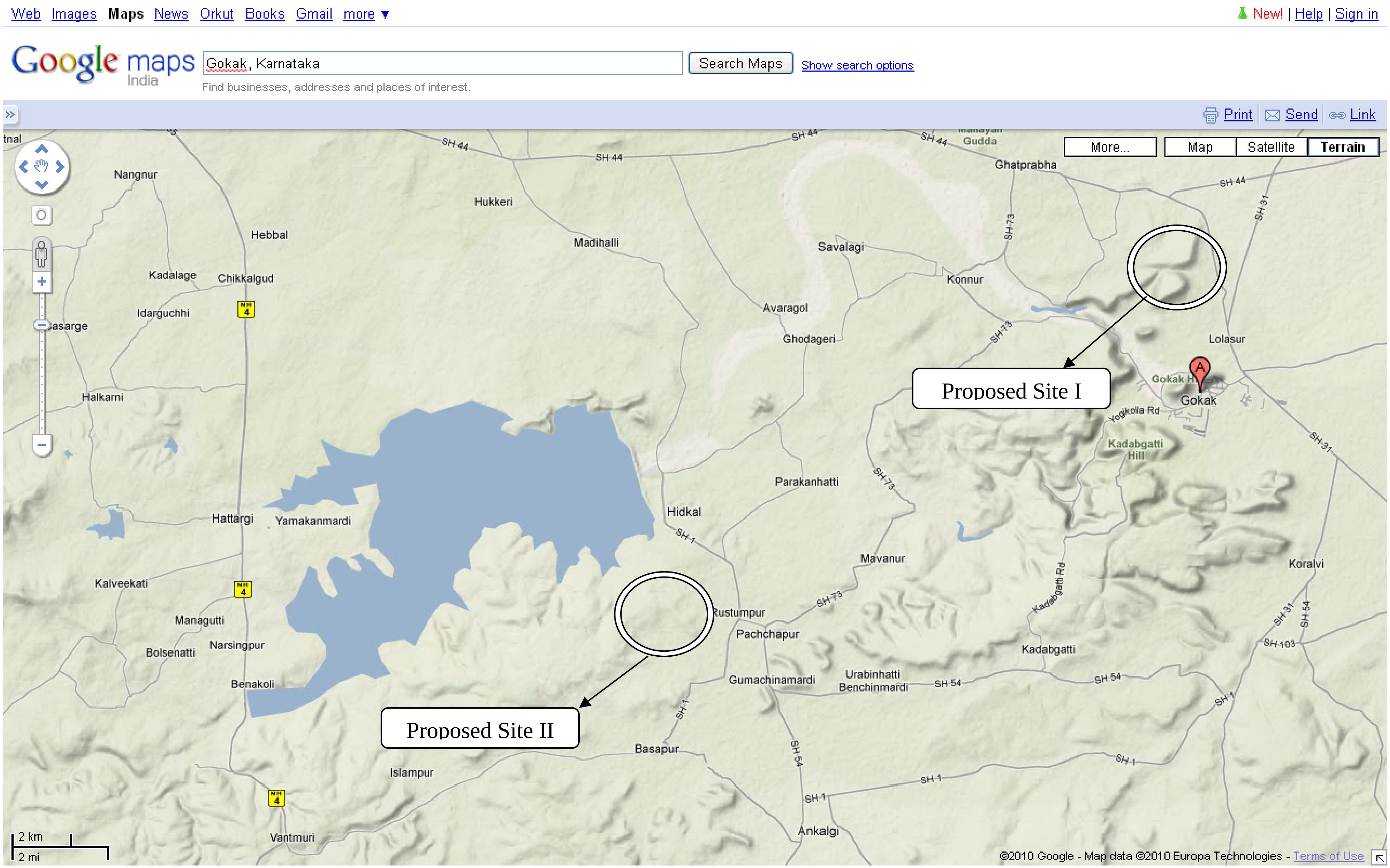


Figure 3.17: Location map showing the proposed project site

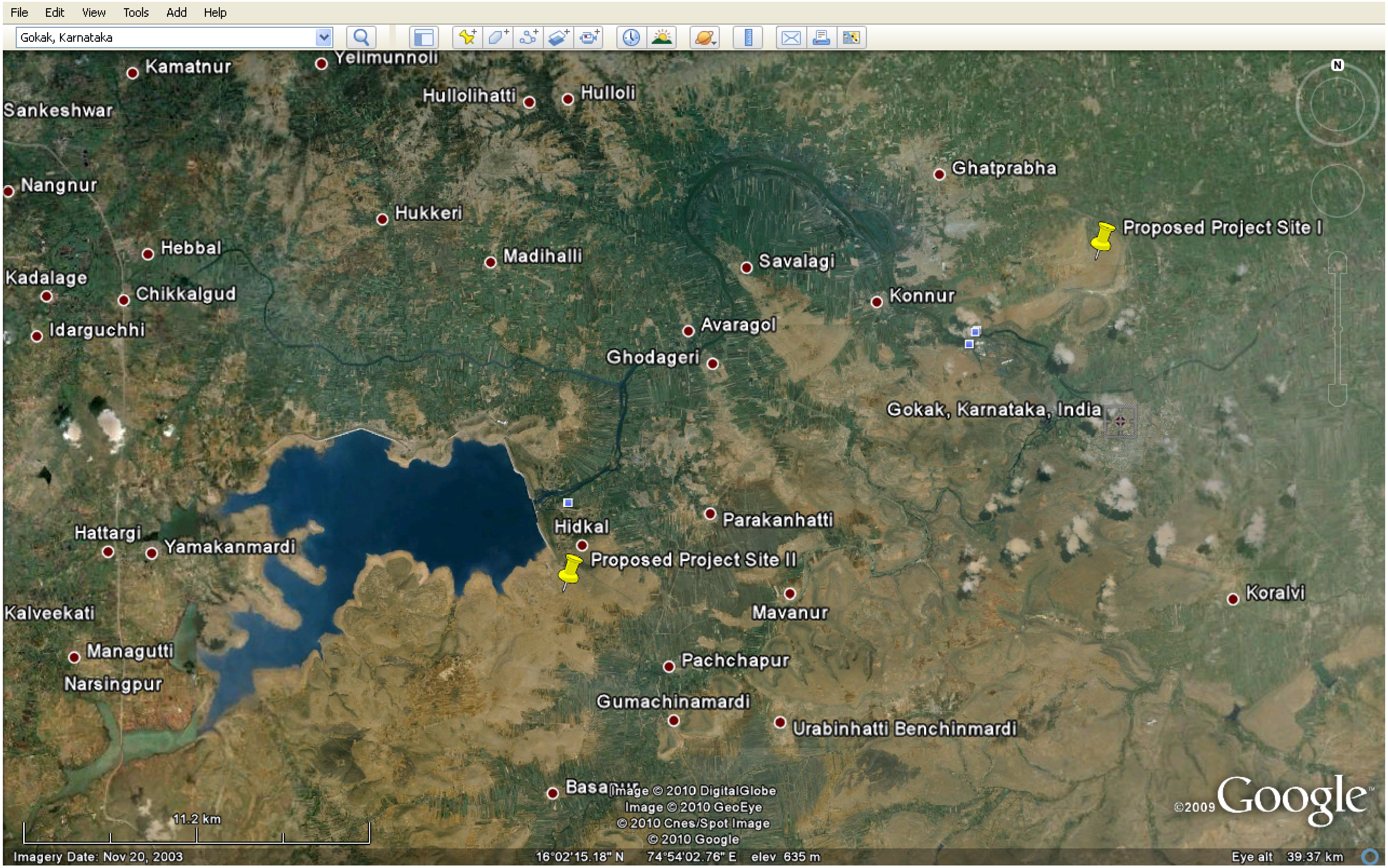
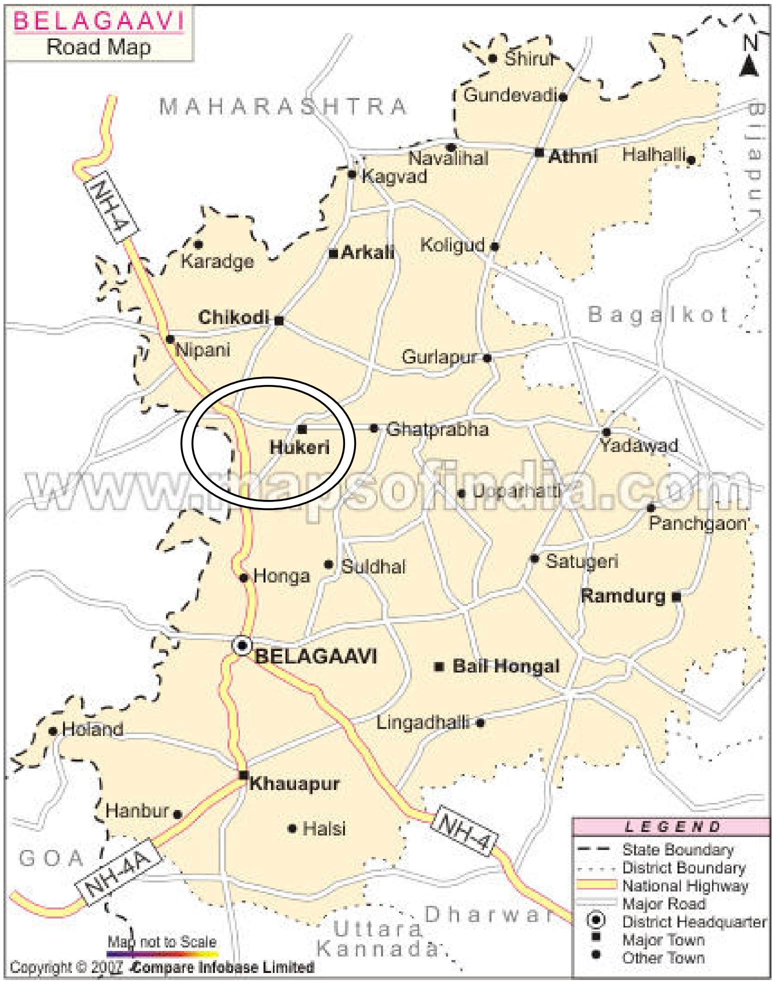


Figure 3.18: Location map showing the proposed project site

3.5.3 Accessibility

As shown in Figure 3.19 the site is around 8-10 km from the National Highway – 4 (NH-4). There is an approach road available and the site can be easily accessed.

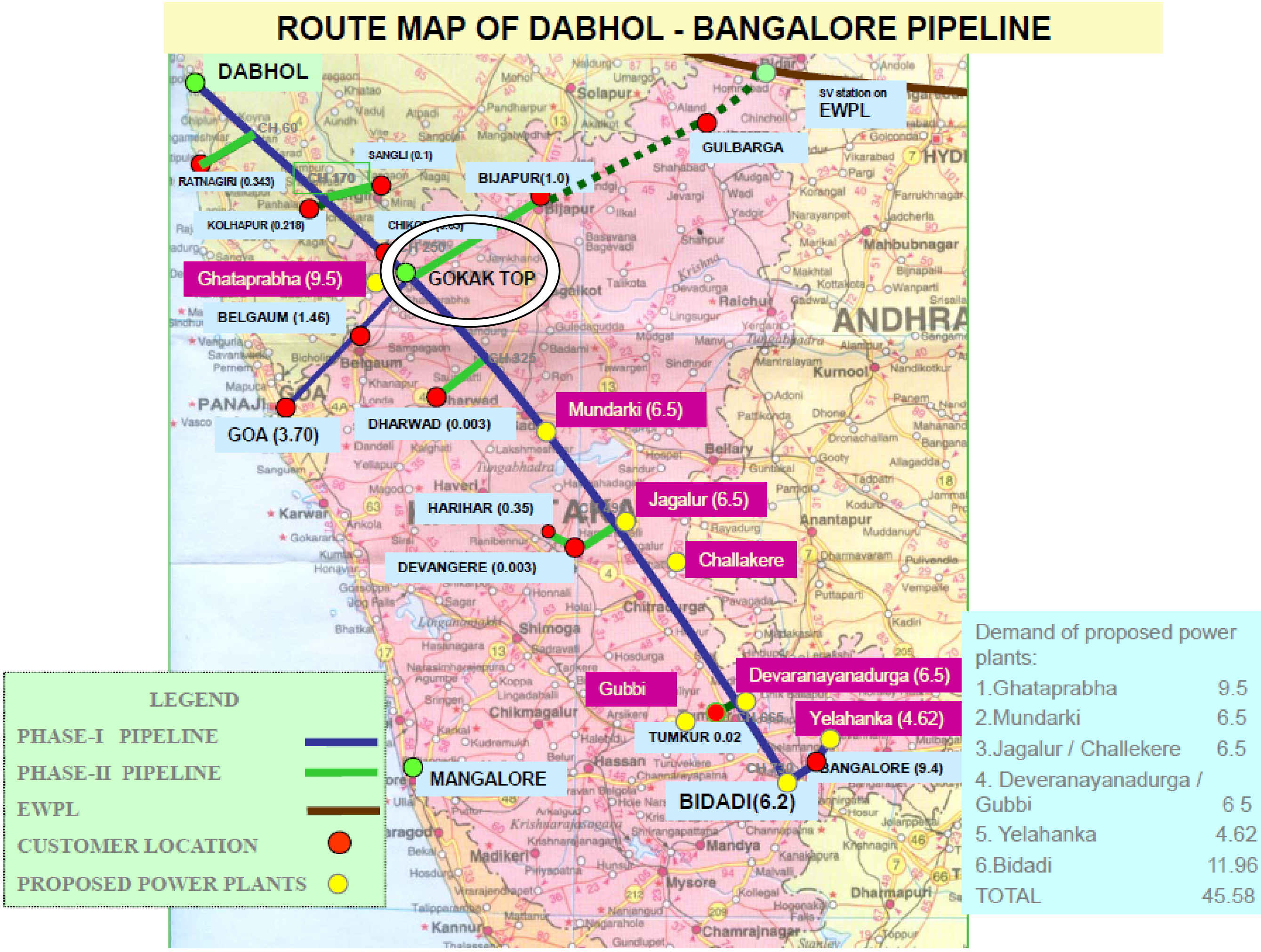


Source: www.mapsofindia.com

Fig 3.19: District Map indicating the location of the proposed project site

3.5.4 Fuel

GAIL has proposed to implement 30 inch diameter, 730 kilometer long Dabhol – Banglore pipeline that is being designed to carry 16 mmscmd of gas and it has signed an MoU with State Govt. for putting up this pipeline. As shown in Figure 3.20, the nearest available Gas tapping from the proposed Dabhol- Bangalore gas pipeline being laid by M/s. GAIL is about 20 Km at Gokak. A spur line can be laid from this tap point to the project site.

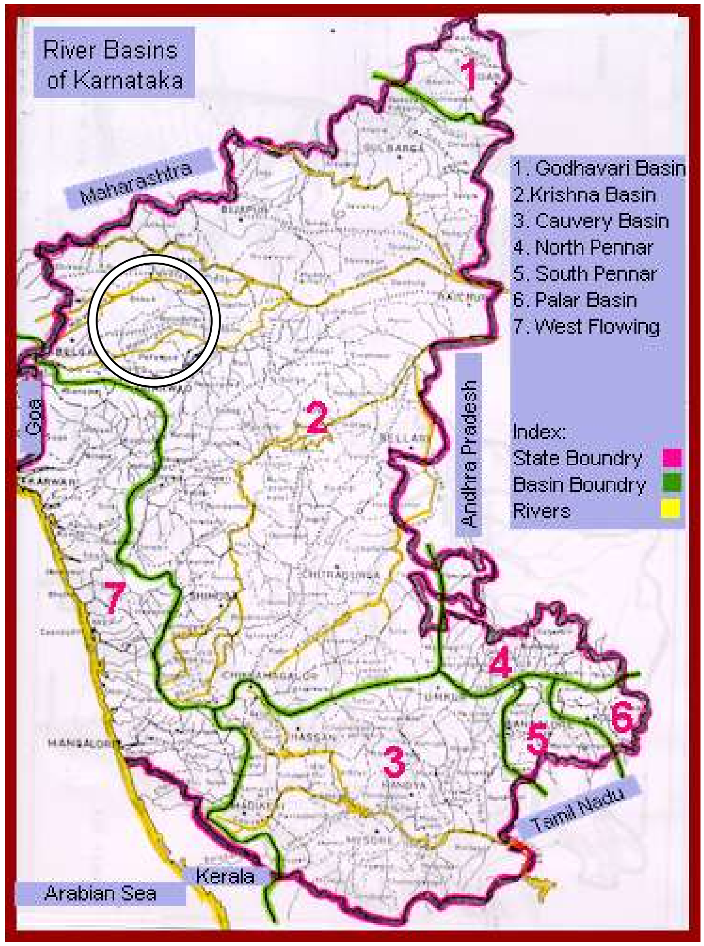


Source: Gas Authority of India Limited (GAIL)

Fig. 3.20: Route Map of Dabhol – Bangalore Pipeline

3.5.5 Water

Ghataprabha River is identified as the water source for the project and it is proposed to draw from the water from the nearby Hidkal Dam that is approx. 5-10 km away from the proposed project site. Around 35-40 cusec of water availability needs to be assured from the Water Resource Department. The river system of the State is shown in Figure 3.21.

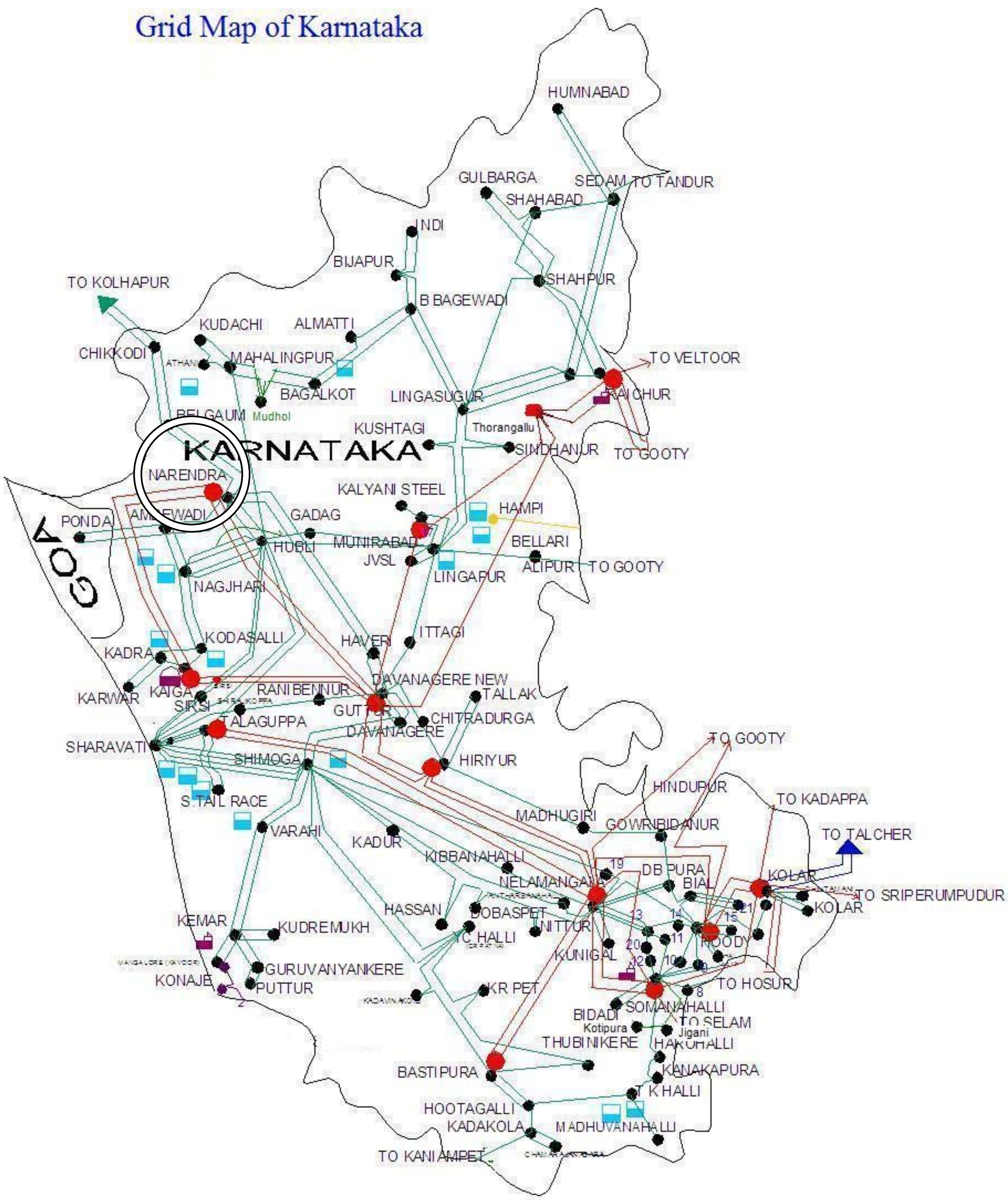


Source: Water Resource Department, Karnataka

Fig. 3.21: River System of the Karnataka State

3.5.6 Power Evacuation

220 KV Ghataprabha sub-station belonging to Karnataka Power Transmission Corporation Limited is within 30 km of the Project site. Also, 400 KV Narendra sub-station belonging to Power Grid Corporation of India Limited is about 110 km from the proposed Project site. The Grid map of the State is shown below in Figure 3.22.



Source: State Load Despatch Centre

Figure 3.22: Grid Map of Karnataka

3.5.7 Others

Ghataprabha Wildlife sanctuary is located at about 15 km from the proposed project site. This is located in Belgaum district and is spread over 20.78 km^2. This sanctuary is known for migratory birds like demoiselle crane and European white stork. Considering the guidelines of Ministry of Environment & Forest (MoEF) of maintaining minimum 10 km distance from any nearby environmental spot, the proposed project is at a comfortable distance from the said sanctuary. However, it is recommended to get a confirmation from the State Forest Department regarding the distance while selecting the exact site area of about 500 acres to avoid any hurdles during the environmental clearance stage for the project.

4. Project Details - Technical

4.1 Technology

The proposed CCGT power plant will operate on Bryaton Cycle at top and Rankine Cycle at bottom.

The gas turbine (GT) operates on Brayton cycle; wherein the ambient air will be drawn to compressor through filters and will be compressed. In combustor, the compressed air will be heated by combustion of fuel. The high pressure-high temperature gas from combustor will be expanded in turbine section to pressure just good enough to drive the gas through the Heat Recover Steam Generator (HRSG) and stack.

The exhaust flue gas from gas turbine will be still at very high temperature. This waste heat from exhaust gas will be recovered in HRSG to generate high pressure-high temperature steam, which in turn will be expanded in steam turbine (ST) and condensed to water in the attached surface condenser. The condensate from the condenser will be pumped back to HRSG. This steam-water cycle connected to HRSG will operate on Rankine cycle.

After absorbing the heat energy of GT exhaust gas, it will be exhausted to atmosphere.

4.2 Power Plant Configuration

No. of Power Blocks and Plant Capacity

The following Combined Cycle Power Plant capacity has been considered for the purpose of this report.

700 MW in phase-I with expansion to 2100 MW with addition of 700 MW in phase – II and phase – III with a 3 month gap between phase – I, II and III

Plant Configurations Available in the market for the plant capacity under consideration

The standard CCPP configurations available currently from the various manufacturers and their ISO output are published in the ‘Gas Turbine World Performance Specs 2005'. This book has been referred in choosing the selection of the plant configuration for the proposed CCPP. In addition ‘GTPRO’ program from Thermoflow Inc, USA, which assists in the selection of the gas turbine power generating units, has been used for estimating the output of CCPP under site conditions at Nedunooru at full load. The models available from leading gas turbine manufacturers namely Alstom, General Electric (GE), Siemens and Mitsubishi have been considered.

Based on the GT World Handbook 2005 a list of possible configurations has been identified for the CCPP. The site output of such configurations was verified using the GTPRO program. The possible plant configurations, the site output, heat rate, etc. for 700 MW (option – 1) and 350 MW (option - 2) are presented in the tables 4.3, 4.4 and 4.5.

The following two (2) alternative Combined Cycle Power Plants configurations have been considered for further study and plant configuration selection:

(a) Option – 1: 3 blocks of 700 MW in 3 Phases

(b) Option – 2: 6 blocks of 350 MW in 3 Phases in single shaft or multi shaft configuration with 2 blocks of 350 MW in each phases

Table – 4.1

Brief Technical Parameters and Performance of possible CCPP (Option – 1: 700 MW with 2GT + 2 HRSG + 1ST in Multi-Shaft Configuration)

Sl.No	Manufacturer	CCPP Model	No of GTs + STs	Performance at ISO Conditions			Performance at Site conditions					
				Gross Output of the plant MW	GTG Output MW	STG Output MW	Gross output of the plant MW	GTG Output MW	STG Output MW	Gross Heat Rate of the plant kcal/kWh +	Efficiency %	Aux power MW **
1	GE	2 X 109 FA	2 + 1	794.40	508.20	289.20	674.67	427.74	246.93	1546.58	55.60	15.37
2	MHI	2 X M 701F	2 + 1	835.60	547.60	288.00	694.86	452.97	241.88	1534.40	56.04	16.01
3	SIEMENS	2 X V 94.3A	2 + 1	826.80	538.80	288.00	700.20	460.81	239.38	1524.60	56.40	15.37
4	ALSTOM POWER *	2 X KA 26-1	2 + 1	850.30 *	Not available	Not available	725.09	453.88	271.21	1520.54	56.55	18.13

* Details obtained from published literature as GT World Performance Specs 2005 does not indicate these values. The value indicated here is net output.

** The Aux power consumption is as per the HBD's generated by GT pro.

+ The heat rate is calculated on the LHV basis

Table – 4.2

Brief Technical Parameters and Performance of possible CCPP Configurations (Option – 2 : 350 MW) 1GT + 1HRSG + 1ST (Single-Shaft Configurations)

Sl.No	Manufacturer	CCPP Model	No of GTs + STs	Performance at ISO Conditions			Performance at Site conditions					
				Gross Output of the plant MW	GTG Output MW	STG Output MW	Gross output of the plant MW	GTG Output MW	STG Output MW	Gross Heat Rate of the plant kcal/kWh +	Efficiency %	Aux power MW **
1	GE	1 x 109 FA	1 + 1	395.90	-	-	339.25	-	-	1537.74	55.92	8.519
2	MHI	1 x M 701F	1 + 1	416.40	-	-	352.30	-	-	1528.90	56.24	8.589
3	SIEMENS	1 x V 94.3A	1 + 1	407.00	-	-	351.05	-	-	1520.54	56.55	8.425
4	ALSTOM POWER	1 x KA 26-1	1 + 1	424.00 *	-	-	364.10	-	-	1514.09	56.79	9.075

* Details obtained from published literature as GT World Performance Specs 2005 does not indicate these values. The value indicated here is net output.

** The Aux power consumption is as per the HBD's generated by GT pro.

+ The heat rate is calculated on the LHV basis

Table – 4.3

Brief Technical Parameters and Performance of possible CCPP Configurations (Option – 2 - 350 MW) 1GT + 1HRSG + 1ST (Multi-Shaft Configurations)

Sl.No	Manufacturer	CCPP Model	No of GTs + STs	Performance at ISO Conditions			Performance at Site conditions					
				Gross Output of the plant MW	GTG Output MW	STG Output MW	Gross output of the plant MW	GTG Output MW	STG Output MW	Gross Heat Rate of the plant kcal/kWh+	Efficiency %	Aux power MW **
1	GE	1 x 109 FA	1 + 1	395.90	254.10	141.80	338.14	213.87	124.27	1542.76	55.74	8.533
2	MHI	1 x M 701F	1 + 1	416.40	273.80	142.60	351.49	229.81	121.68	1532.48	56.12	8.607
3	SIEMENS	1 x V 94.3A	1 + 1	407.00	Not available	Not available	350.37	230.41	119.97	1523.41	56.45	8.457
4	ALSTOM POWER	1 x KA 26-1	1 + 1	424.00 *	Not available	Not available	362.89	226.94	135.95	1519.12	56.61	9.108

* Details obtained from published literature as GT World Performance Specs 2005 does not indicate these values. The value indicated here is net output.

** The Aux power consumption is as per the HBD's generated by GT pro.

+ The heat rate is calculated on the LHV basis

Notes:

1. The Gross Power output, Heat Rate and Efficiency of the CCPP's at site conditions are based on Thermoflow software and may differ a little with actual output and efficiency offered by the manufacturers.
2. The CCPP models and ISO ratings are based on "Gas Turbine World; 2005 Performance Spec Handbook" and published literature.
3. The output and heat rate are based on following:

   - NG analysis: as per Appendix-I
   - Ambient temperature: 330C
   - Relative Humidity: 69%
   - Wet bulb temperature: 28 0C
   - Altitude: 288 m above MSL
   - Condenser inlet cooling water temperature: 33°C
   - Temperature rise across condenser: 100C

4. Limitations of software:
   - 100% methane is the fuel for Alstom's KA 26-1model

Selection of Plant Size and Configuration

The total output at site conditions is about 2100 MW, in 3 phases. This is possible to be achieved considering the configurations listed out in table - 4.1, table - 4.2, and table - 4.3 above.

Discussions on various Configurations:

Option -1: 700 MW Block with 2 GTG + 2 HRSG's and 1 STG

Table 4.1 lists out the 2 GTG + 2 HRSG + 1 STG configurations from leading manufacturers viz. GE, MHI, Siemens and Alstom which gives an output nearing to about 700 MW at site conditions. The site gross output varies from about 674 MW to about 725 MW and the efficiency varies from 55.6% to 56.6%. This configuration will be suitable for base load application. In these configurations, the gas turbine and steam turbine design can be separated. The auxiliary power consumption varies from about 15.37 MW to 18.13 MW

In the 2 GTG + 2 HRSG + 1 STG configuration the steam turbine capacity would be about 250 MW. In such a case bottom mounted condensers is likely to be offered. This would increase the civil works costs as the turbine building height would have to be increased to accommodate this type of condenser. The normal practice in combined cycle power plants would be to provide axial condensers to avoid floors in the turbine building, there by reducing the height of the turbine building. This will not be possible in this configuration

During the major overhaul of the steam turbine which is likely to take place once in about 5 years, one block of 700 MW would be out of service for the period of overhaul.

The HRSG's will have to be shut down for annual inspection. This could be planned in such a way that the HRSG's are inspected sequentially. During such annual maintenance or inspection of the HRSG, one of the HRSG's would be out of service. Then the associated gas turbine would also have to be shut down. In such a case the steam turbine would be operating in part load condition with one GT and one HRSG in service.

i) The area required for the 700 MW power block comprising of 2 GTG's, 2 HRSG's and 1 STG along with their auxiliaries would be about 130 m x 130 m.

ii) The number for generators of a typical block of 700 MW power island in multi shaft configuration would be three (2 for GT and 1 for ST) and for the ultimate capacity of 2100 MW comprising 3 blocks each of 700MW there would be 9 generators and there would be 9 numbers associated generator transformers.

iii) Advanced class machines in the configuration of 2 GTG + 2 HRSG and 1 STG have been successfully operating at many places in the world and are proven in technology. At present there are no installations in India, with advance class machines in the above configuration. However with this configuration there are no disadvantages as such except for some drawbacks as listed above.

<u>Option 2 : 350 MW Block with 1 GTG + 1 HRSG and 1 STG in single shaft configuration</u>

The table 4.2 lists out the 1 GTG + 1 HRSG + 1 STG in single shaft configuration from leading manufacturers viz. GE, MHI, Siemens and Alstom which gives an output nearing to about 350 MW at site conditions. The site gross output varies from about 339 MW to about 364 MW and the efficiency varies from about 55.92% to 56.79%. This configuration would be suitable for base load application. The start-up time is shorter and the operation would be simpler compared to the multi-shaft configuration. Here the Gas turbine and steam turbine design has to be coordinated as the GT, HRSG and ST would be offered as a single block. The auxiliary power consumption varies from about 8.425 MW to 9.075 MW

The area required for two blocks of 350 MW (totalling to 700 MW) power island, each block comprising of 1 GT, 1HRSG and 1 ST and a common generator along with their auxiliaries in single shaft configuration would be about 125 m x 185 m.

The number of generators for a typical block of 350 MW power island in single shaft configuration would be one (common for both GT and ST) and for the ultimate capacity of 2100 MW comprising totally 6 blocks of 350 MW, there would be 6 generators. The size of these generators would be well above 350 MW, and the associated generator transformers would be about 450 MVA.

Option – 3: 350 MW Block with 1 GTG + 1 HRSG and 1 STG in multi shaft configuration

Table 4.3 lists out the 1 GTG + 1 HRSG + 1 STG in multi shaft configuration from leading manufacturers viz. GE, MHI, Siemens and Alstom which gives an output nearing to about 350 MW at site conditions. The output varies from about 338 MW to about 362 MW and the efficiency varies from 55.74% to 56.6%. This configuration is suitable for base load application. In this configuration, gas turbine and steam turbine design could be separated.

The area required for two blocks of 350 MW (totalling to 700 MW) power island, each comprising of 1 GTG + 1 HRSG + 1 STG along with their auxiliaries in multi shaft configuration would be about 210 m x 150 m.

The number of generators of a typical block of 350 MW power island in multi shaft configuration would be two (1 for GT and 1 for ST) and for the ultimate capacity of 2100 MW comprising totally 3 blocks of 700 MW, (i.e. each block having 2 x 350 MW), there would be 12 generators and 12 numbers associated generator transformers.

Recommendation of CCPP configuration for the power plant

From the above, it may be concluded that for the proposed 2100 MW CCPP with three phases of expansion with each phase having about 700 MW installations, as listed above in Option – I would be technically acceptable based on proven performance data. However, to attract wider competition, it is recommended to retain all the three configurations.

4.3 Main Plant

Gas Turbine Generator & Accessories

The gas turbine will be heavy duty, advanced class type each comprising of a multistage axial compressor and a turbine including combustors section.

The inlet air system would consist of a filter house with self-cleaning pulse jet type or two stage static air filters, ducting and silencer. The system would draw atmospheric air into the gas turbine compressor unit.

Air intake silencer will suppress the noise in the intake air system. An inlet air guide vane will be provided in the compressor to improve the efficiency of the plant under part load conditions. The turbine will have multiple stages. The exhaust gas from the advance class gas turbines are generally in axial direction of the gas turbine. The gas turbine units will have Dry Low NOx (DLN) combustors suitable for burning natural gas only.

Depending on the fuel gas specification of GT manufacturer's, a water bath / steam heater type fuel gas heater would be provided prior to combustor to ensure that no condensate enters the combustor. Further, these heaters also would improve the net heat rate of the Power plant, which is a consequential benefit. The combustion fuel mixture with air takes place in the combustors and the hot gas will be expanded in the gas turbine, which will drive the generator as well as axial flow air compressor. The gas turbine will have a rated speed of 3000 rpm for direct coupling with generator.

The gas turbine generator will be provided with lubrication oil system complete with lube oil pumps, lube oil reservoir, and lube oil coolers.

The exhaust system of gas turbine will exhaust the gas into the atmosphere through HRSG.

It is general practice with advanced class gas turbines to have a static frequency converter (SFC) to use the generator itself as motor during starting of GT. This option eliminates the starting motor / starting engine which are general features of the lower class gas turbines, but the option of starting motor would also be available with some of the advanced class GT suppliers. However, the option for SFC as well as Starting Motor will be also be given to EPC Contractor and acceptance will be subjected to suitable design of transformer and plant electrical system.

A fire detection and carbon dioxide / clean gas protection system as per GT manufacturer's standard practice (which will be generally compliant to recommendations of NFPA / equivalent norms) will be provided to protect the gas turbine and its auxiliaries against fire hazard.

Heat Recovery Steam Generators

The HRSGs, which have been contemplated for the proposed project will be unfired type with horizontal gas, flow, natural circulation with triple pressure (High, Intermediate and Low pressures) steam generation. The HRSGs will have the dry run capability in order to reduce the black-start power consumption.

Each HRSG will have a separate Superheater, Evaporator and Economizer sections to generate High Pressure (HP), Intermediate Pressure (IP) and Low Pressure (LP) steams. Further, the HRSGs will also have a reheater section where, the cold reheat steam from the HP turbine after integration with IP steam from IP evaporator will be superheated. Steam temperature control at each super heater section will be achieved with spray water attemperation. The spray for attemperators will be tapped-off from HP feed water line.

In each HRSG, a condensate pre-heater (CPH) has been envisaged to recover the thermal energy of the hot gas to the maximum extent. The gas temperature at outlet of CPH is generally governed by dew point temperature of oxides of sulphur. Though the sulphur content in the gas is nil, the design exit gas temperature has been limited to 90ºC based on the optimisation of the heat transfer area of condensate pre-heater.

It has been envisaged that the Deaerator will be integral part of the HRSG, which will be getting heating steam from the LP evaporator. However, option will be given to EPC Contractor for external Deaerator, where the heating steam for Deaerator would be supplied from LP steam header after pressure regulation. Vent condenser would be provided with the Deaerator to minimise wastage of steam. The Deaerator will be constant pressure, spray or spray-cum-tray type and will be designed to deaerate all the incoming condensate to keep the oxygen content of the deaerated condensate below the permissible limit, which generally 0.005 cc/litre and maximum carbon dioxide in deaerated feed water would be nil. The steam from LP evaporator will be used to peg the Deaerator during plant operation.

HRSG will be provided with internal thermal insulation, platforms and ladders as required. Feed water and steam sampling arrangements as required would be provided.

Each HRSG will be provided with a 60m high self-supporting steel stack. As such no sulphur has been found in the natural gas fuel and hence, Central Pollution Control Board (CPCB) norms based on sulphur in fuel would not be the governing factor for stack height. Stack height has been arrived to balance the net draft available at stack inlet; however, this will also assist in better dispersion of hot flue gas from HRSG and NOx emission.

Steam from the HRSGs would be supplied to a steam turbine through steam piping. Intermediate-pressure (IP) and Low-pressure (LP) bypass systems of 100% HRSG capacity will be provided for dumping the IP and LP steam to the condenser during start-up and turbine trip conditions. During by pass condition, the HP steam will be depressurized and desuperheated to cold reheat steam condition and will be integrated with IP steam before HRSG reheater section. Each bypass station will be provided with pressure reducing valves and attemperators as necessary. The spray water for attemperation would be tapped-off from IP feed water line.

Steam Turbine & Auxiliaries

For the purpose of this project report, non-extraction, re-heat, condensing type steam turbine has been considered. The steam entry to the turbine would be through a set of emergency stop and control valves, which would govern the speed / load of the machine. The turbine control system would be of electro-hydraulic type with hydro-mechanical system as a backup.

The steam turbine would be complete with lube oil and control oil system, jacking oil system, governing system, protection system and gland sealing steam system. The lube oil system of the STG will be provided with 2x100% online centrifuge system.

The gland sealing steam for the steam turbines would be taken from HP steam and will be de-pressurized and de-superheated before supply to turbine glands. The spray water for de-superheating would be taken from IP feed water line. The gland steam header of both power blocks would be interconnected to provide the flexibility during steam turbine start-up and reduce the start-up time.

Condensing Equipment & Auxiliaries

The steam turbine would be provided with a surface type condenser fixed to the turbine exhaust for condensing the exhaust steam from the steam turbine. The condenser would be of radial or axial or lateral configuration with rigid or spring mounting arrangement as per EPC Contractor’s standard practice.

The condenser design will be ensured to prevent sub-cooling of condensate below saturation temperature corresponding to respective condenser backpressure under any of the operating conditions. While deciding the heat duty of the condenser, the heat load during steam dumping will also be considered as one of the operating conditions. Oxygen content of condensate leaving the condenser hot well will be ensured not to exceed 0.03 cc/litre over the entire range of load. The design will be to satisfy the requirement of Heat Exchanger Institute (HEI), USA.

Two (2) Nos. (1 Working + 1 Standby) capacity vacuum pumps or steam jet air ejectors will be provided to maintain the vacuum in the condenser by expelling the non-condensable gases. One vacuum pump would operate during normal plant operation and during start-up, both the vacuum pumps may be operate such that, the desired vacuum can be pulled within a shortest possible time. In the alternative option of using steam jet ejector, one starting steam jet air ejector of higher capacity will be provided for quick evacuation of gases from the condenser during start-up. Steam for the ejectors will be supplied from the HP steam header after de-pressurising and de-superheating. Further, the steam headers of steam jet air ejectors of both the blocks will be interconnected to have the flexibility of operation during start-ups. The design of vacuum system and it’s sizing will be as per requirement of HEI.

Condensate Extraction Pumps (CEP)

Two (2) Nos. (1 Working + 1 Standby) CEP would be provided to pump the condensate from the hot well to Deaerator through the CPH of the HRSG.

The condensate extraction pumps will be vertical motor driven centrifugal canister type with flanged connections. Between the condenser and the condensate extraction pumps, each line will include a manual shut-off block valve and a strainer. The pumps will discharge through check valves and motor operated stop valves into a common discharge header. The starting of pumps will take the start-permissive from end limit switches of discharge isolation valves-closed to avoid the pump operation at run-off power which reduces the pump motor rating.

Connections for condensate supply to the following major services will be tapped-off from this condensate discharge header:

• Turbine exhaust hood spray.
• Gland sealing system de-superheating.

The condensate will then pass in series through the gland steam condenser before entering the CPH section of HRSG.

Boiler Feed Pumps (BFP) and Drives

Two (2) Nos. (One Working + One Standby) horizontal, multi-stage, barrel casing / ring section, centrifugal type BFP, driven by electric motor, will be provided for HP feed System. Each HP BFP would have one (1) no. matching capacity, single-stage booster pump driven by the feed pump motor. The booster pump will take suction from feed water storage tank and discharge into the suction of corresponding main BFP, which in turn will supply feed water to HP section of HRSG through HP feed water control station. HP feed water control station comprising of Two (2) Nos. (One working + One standby) pneumatic control valves of 100% and one (1) no. 30% capacity pneumatic control valve has been envisaged to control the HP drum level. Each feed water control valves will be provided with motor driven upstream isolation valve and a downstream isolation valve with manual operator for maintenance of internals of control valve.

All the feed pumps will be provided with minimum flow re-circulation control arrangement to protect the pump under low load operation. The pumps will discharge through minimum flow re-circulation valves and motor operated stop valves into a common discharge header. The starting of pumps will take the start-permissive from end limit switches of discharge isolation valves-closed to avoid the pump operation at run-off power which reduces the pump motor rating.

Each pump will be provided with mechanical seals with proper seal cooling arrangement, self-contained forced lubricating oil system for supplying oil to the bearings, couplings etc. The lubricating oil and also sealing arrangement of the feed pumps will be cooled by closed cooling water system utilising demineralised water as cooling medium. All necessary protective and supervisory system will be provided to ensure safe and trouble-free operation of the feed pumps.

A similar arrangement as elaborated above, except booster pump, would be provided for IP System. The type of IP BFP would be ring section type.

Alternatively, it is also possible to provide a feed for IP Section from bleed-off HP BFP. The option will be given to Contractor for selection of independent IP BFP or bleed-off type HP BFP to feed IP System.

Chemical Dosing System

Although high purity water will be used as heat cycle make-up, careful chemical conditioning of the feed steam condensate cycle is essential as a safeguard against corrosion and possible scale formation due to ingress of contaminants in the make-up system. Chemical feed system will comprise of the following:

- Hydrazine System
- Phosphate Dosing System

4.4 Mechanical Auxiliary System

Fuel Conditioning System

To meet the fuel gas specifications of gas turbine manufacturer, necessary conditioning system including the gas booster station for natural gas has been envisaged as a part of this power plant project.

The gas conditioning process generally comprises removing condensates, filtration and compressing systems, which will be unitised facility for each power block.

One (1) No., common flow meter will be provided near terminal point for internal fuel auditing. The flow meter would be orifice type with ±1% accuracy. An upstream and downstream isolation valve with a bypass valve will be provided flow meter to enable the maintenance of flow meter.

Each power block will be provided with two (2) streams (1 Working + 1 Standby) each comprising of one (1) no. of Knockout drum to remove condensate and a Cartridge filter to remove particulate matters in the influent natural gas before admitting to compressor. Each gas stream will be sized to cater to the maximum fuel gas demand of respective power block.

To supply the required natural gas during start-up conditions, One (1) no. common black-start gas compressor has been envisaged. The black-start gas compressor would be driven by gas engine and sized for 25% of MCR requirement of one GT in order to reduce the black-start power requirement of the plant. After gas compression, each GT will be provided with a final filter to remove the condensate formed during the compression as well as ingress of particulates in compressor and piping system.

One (1) no. common gas condensate tank of 5m3 capacity will be provided to collect the gas condensates from upstream of gas compressors. The condensate collected in the tank will be pumped to barrels using two (2) Nos.(1 Working + 1 Standby) condensate transfer pumps for off-site disposal of fuel gas condensates. The pumps will have interlock with level switches in tanks for minimum submergence, but should be started manually.

One (1) no. common cold stack of adequate height will be provided at safe location on gas conditioning area, to which all the vent lines of gas system will be connected to disperse the system vents during maintenance and safety valve pop-ups.

Cooling Water System

The proposed power plant being located close to water source, closed cycle cooling water system has been considered for surface condenser of steam water cycle.

The cooling water system will be unitised and it will supply of cold water to surface condenser of steam-water cycle as well as secondary side of the ACW systems of GTG and STG auxiliaries.

Two (2) Nos. (1 Working + 1 Standby) Cooling Water (CW) pumps of vertical type have been considered to supply cooling water to STG condenser. The CW pumps will be located in a cooling water pump sumps, which will receive cooled return water from the cooling tower basin. The cooling water sumps and CW forebay will be sized as per guidelines of Hydraulic Institute Standard.

Considering the high humidity and being located inland, Induced Draft Cooling Tower (IDCT) has been considered for proposed power plant to cool the hot return water from Surface Condenser of ST. Generally, the construction period of IDCT is less when compared to natural draft cooling tower, which is an added advantage.

The IDCT will have cells each comprising of fans and film type PVC fills mounted on RCC basin. It is proposed to provide adequate Nos. IDCT cells with one no. cell as a spare. The cooling tower cells will be arranged in-line to reduce the re-circulation of hot air and to ensure effective cold airflow to cooling towers. The cooling tower would be designed for a cooling range of 10°C. Each cooling water cell will be provided with individual cold-water basin, trash screen and gate. The cold-water basin of each cell will be sized to hold 6 minutes water flow (between liquid levels corresponding to normal operating level and low-low level / level corresponding to trip of CW pumps in CW forebay) from respective cell.

The make-up for the cooling water system will be from clarified water storage tank. The cooling water make-up pumps would start and stop based on level signals from level switches in forebay. To ensure adequate dissolvability of scales, the CW system make-up has been sized based on cycle of concentration (COC) of 3 - hence, no anti-scalants / dispersants chemical dosing have been envisaged for CW system. It is recommended to use package chemicals to attain higher COCs provided the discharge parameters are with in the statutory norms. However, chlorine gas dosing system will be provided to prevent formation of algae and other biological growths. The CW chlorination system would comprise chlorine tonners, evaporators, motive water pumps, chlorinators, chlorine gas distribution system, chlorine leak gas absorption system, etc. The chlorination system equipment will be located in a room adjacent to CW Pumphouse. The Chlorination system will be sized to dose 5 mg/l of CW water in the system for 30 minutes per 8-hour shift. The total number of tonners per block will be based on requirements of 15 days of chlorine requirement of respective block.

Auxiliary Cooling Water (ACW) and Closed Cooling Water (CCW) System

The CCW system meets the cooling water requirements of all the auxiliary equipment of the GTG, STG and HRSG units such as turbine lube oil coolers, generator coolers, BFP auxiliaries, condensate pump bearings, sample coolers and air compressors auxiliaries. The GTG and STG / HRSG auxiliaries will be provided with an individual ACW systems since the pressure requirements of cooling water system of GTG is generally high when compared to auxiliaries of STG and HRSG.

The primary side of this cooling water system for auxiliaries, i.e., circulating cooling water (CCW) system will make use the passivated DM water as cooling medium, which will be circulated in closed circuit through plate heat exchanger and auxiliary coolers in series. Two (2) Nos. (1 Working + 1 Standby) CCW pumps per circuit will be provided to circulate the water in closed primary circuit. An overhead expansion tank of adequate capacity will be provided to ensure positive suction to the CCW pumps as well as will allow the expansion of water in closed circuit. There would loss in water level in CCW circuit due gland leakage at pumps, leakages in flanged connections, at plate heat exchanger seals, etc. To make-up this loss, the make-up water would be supplied from CEP discharge during normal operation. Solenoid operated level control valve will be provided on expansion tank to ensure the level in tank. During initial fill for the system, water will be supplied from HRSG fill pumps discharge. A chemical feed system will be provided to add chemicals for passivation of DM water and ensure adequate pH value.

The hot water from auxiliary coolers in primary circuit will dissipate the heat to cooling water from Condenser cooling water system in secondary circuit. For this purpose, two (2) Nos. (1 Working + 1 Standby) Plate Heat Exchangers (PHE) per each circuit has been envisaged. The cooling water in secondary circuit (ACW system) will be cooled in turn in IDCT of condenser cooling water system. Two (2) Nos. (1 Working + 1 Standby) ACW pumps per circuit will be provided to circulate the water in secondary cycle through plate heat exchanger and IDCT. The ACW pumps will be located in CW Pumphouse and will take suction from cooling water sump.

Central Lube Oil System

The plant will be provided with central lube oil system for the purpose of storing and treatment of lube oil for Steam turbine and auxiliaries. Generally, for the gas turbine, the manufacturers would not accept to use the treated lube oil. For gas turbine lube oil system, the properties will be monitored at regular interval and will be replaced after the properties deteriorate beyond the recommended values by manufacturer.

The central lube oil system will be provided with one (1) no. dirty lube oil tank and one (1) no. clean lube oil tank. Each lube oil tank will be sized for storage of fill capacity of lube oil system one STGs. Two (2) nos. (1 working + 1 standby) lube oil transfer pumps with suitable valving arrangement and duplex suction strainers will be provided to transfer the lube oil from STG main lube oil tank to dirty lube oil tank and from clean lube oil tank to STG main lube tank.

One (1) no. Lube oil centrifuge (manual discharge type) along with one (1) no. Lube oil feed pump will be provided to centrifuge the dirty lube oil tank. The lube oil feed pumps will take the suction from untreated lube oil tank and after centrifuging, it will discharge the treated lube oil to clean lube oil tank. The Centrifuge will be sized adequately to turnover the dirty oil tank in 6 hours.

The clean lube oil tank will also be used to store the new lube oil supply from the supplier. For the purpose of transferring the lube oil from suppliers drums to clean lube oil tank, one (1) no. Barrel type unloading pump has been envisaged. The lube oil tanks and centrifuge will be located inside a dyke of adequate capacity to contain the leakages and spillages during operation and any other eventualities.

Fire Fighting System

For protection of power plant equipment and operating personal against fire, any one or a combination of the following systems will be provided for all yards, areas, buildings and equipment:

- Hydrant system – Entire Plant,
- Medium Velocity Water Spray System – Cable Gallery,
- High Velocity Water Spray System - Transformers and LO Tanks,
- Portable Fire Extinguishers – Entire Plant,
- CO_2 / Clean Agent Systems – Switchgear Rooms, Control Rooms,
- Sprinkler System for Office Buildings,
- Foam cabinets and portable foam system,
- Fire resistant doors and fire seal walls will be provided as per code requirements

The system will be designed in conformity with the recommendations of the Tariff Advisory Committee of Insurance Association of India.

Compressed Air System

Two (2) Nos. (One working + One Standby) plant oil free screw type air compressors of adequate capacity at discharge pressure of 8.5 kg/cm2 (g), along with compressed air receiver will be provided to cater the plant compressed air requirement. The service air system and the instrument air system will be separate in all respects.

One (1) no. Plant air receiver of adequate capacity considering the steady and transient state requirement will be provided. A separate plant air receiver will supply air to service air requirements of plant including pneumatic tools, workshops, cleaning of filter elements, floor cleaning, etc. Further, another plant air receiver will also supply the compressed air to plant instrument air system after filtration and dehumidification to a quality acceptable by Instrument air consumers (covers pneumatic actuators and pulse jet air to GT inlet air filters during non-availability of air from GT air compressor). For this purpose, a redundant air filters and air-dryers have been envisaged. The instrument air drying system will consist of two (2) Nos. identical desiccant type-drying towers with pre-and-post-filters. Normally, one of the dryers will be in service while the other one will be under regeneration. A completely automatic control system will sequentially control the driver system to ensure timely regeneration and service to provide dry air at the outlet at all times. An Instrument air receiver will be provided after filter and dryer as a buffer to ensure the startup during plant blackout condition, etc.

Cranes & Hoisting Equipments

Based on probable layouts, the following cranes would be required for maintenance of GTG and STG:

- Common EOT Crane for GT of both the bocks. The capacity of this Crane will be decided based on heaviest equipment to be handled during maintenance i.e. generally rotors of compressor and turbine.
- Individual EOT Crane for Generator of each GTG. The capacity of this Crane will be decided based on heaviest equipment to be handled during maintenance i.e. generally generator rotor.
- Common EOT Crane for STG of both the blocks.

The capacity of this Crane will be decided based on heaviest equipment to be handled during maintenance i.e. generally generator rotor. Further to above, following Cranes & hoist have been envisaged for maintenance of major equipment:

- EOT Crane for CW Pump house
- EOT Crane for Gas Compressor Building
- EOT Crane for Work Shop
- EOT Crane for Black-start Diesel Engine Room
- Monorail with hoist for River Water Pump house
- Monorail with hoist for Raw Water Pump house
- Monorail with hoist for Clarified Water Pump house

- Monorail with hoist for BFP Room

Air-Conditioning System

Various control rooms in power station - houses a group of sophisticated and precision control panel and desks, which call for controlled environments for proper functioning. For control rooms, the objective of air-conditioning is to maintain conditions suitable for satisfactory functioning of sophisticated equipment, accessories and controls and also for personnel comfort. Besides these, the service areas viz. instrument and relay testing laboratories chemical laboratory and a few offices are envisaged to be air-conditioned.

The following areas are proposed to be air-conditioned:

- All unit control rooms, local control rooms, computer rooms, control equipment rooms.
- Switchyard control room.
- Service areas viz., chemical laboratories, I&C testing laboratory, relay and meters testing laboratory, SWAS (dry panel area) and gas analyser rooms, etc.
- Office block located in the powerhouse
- Some of the rooms in Security buildings

Ventilation System

For all the areas other than air-conditioned area the general ventilation system will be provided with the following objective:

- Dust-free comfortable working environment.
- Scavenging out heat gain through walls, roofs, etc. and heat load from various equipment, hot pipes, lighting, etc.
- Dilution of polluted air due to generation of obnoxious gaseous / aerosol contaminants like acid fumes, dusts, etc.

Plant Process Waste Effluent Water Disposal System

From the proposed power plant site, the following wastewater effluent from process has been envisaged:

- Waste water from neutralization pits of DM Plant.
- HRSG Blowdown.
- GT Compressor Wash water Drain System.
- Oily Water from Transformer Pits.
- Oily Water from Buildings / Areas like lube oil storage tanks, from equipment maintenance area floor drain, etc.
- Cooling Tower Blowdown.
- Gas Condensates from Gas Conditioning Area

4.5 Electrical System

Energy Evacuation Plan

The nominal gross site output envisaged for the proposed power project would be about 1000 MW. After meeting the power requirement of the station auxiliaries, about 965 MW will be available for evacuation.

The power will be evacuated at 400 kV level. To enable this a 400 kV switchyard will be provided. Also, for feeding to the local grid a 220 kV system with ICTs of 100 MVA capacity has been proposed.

Each generator will be connected to the 400 kV switchyard through the respective generator transformer. For feeding the station auxiliaries of the plant and to provide start-up power, redundant station transformers of capacity 25 MVA is proposed.

400 kV switchyard will be provided with 1 ½ breaker switching scheme with the following bays:

- 3 Nos. Gas turbine generator transformer incomers
- 3 Nos. Steam turbine generator transformer incomers
- 3 Nos. 400 /220 kV ICT bays
- 2 Nos. Line feeders with switchable line reactors (50 MVAR)
- 2 Nos. Bus reactor feeder

220kV switchyard will be provided with two bus system and will be provided with the following feeders:

- 2 Nos. Line feeders
- 2 Nos. Station transformer bay
- 1 No. Buscoupler Bay
- 2 Nos. Interconnecting transformer bays

All necessary protections for the above bays will be provided for the 400kV and 220 kV switchyard.

Transmission System

Depending upon the quantum of the power to be supplied to the various customers, the power will be evacuated by a double circuit 400 kV transmission line to nearest 400 kV substation. Alternatively, two nos. 220 kV line feeders can also be provided in the 220kV switchyard to supply to local grid of Karnataka State.

5. Project Approval & Clearance

In order to control and regulate the development of Power Projects by State / Private Sector, a legal framework has been developed by Government of India. Accordingly, several clearances and approvals shall have to be obtained from different Government and Statutory Agencies at various stages of the project. An Indicative list of approvals / clearances to be obtained from Govt. Authorities for this project is presented below:

1)	Water availability and use	:	State Govt. / Central Water Commission (CWC)
2)	Clearance for air and water (sewage & effluent) pollution	:	MoEF, State Pollution Control Board & CPCB
3)	Clearance for handling & storage of Fuel	:	Chief Controller Of Explosives
4)	Boiler pressure parts	:	Chief inspector of Boilers
5)	Plant installation	:	Factory Inspectorate
6)	Electrical installation	:	Electrical Inspectorate
7)	Construction labour	:	Labour Commissioner
8)	Fire fighting	:	Insurance Authority and Local Authority
9)	Civil Aviation clearance	:	Airport Authority of India

6. Environment Aspects

6.1 Introduction

The environmental impact of the proposed power station covering the following aspects and the measures for controlling the pollution within the values specified by Central Pollution Control Board (CPCB) / State Pollution Control Board (SPCB) is briefly discussed in this chapter:

- Air pollution
- Water pollution
- Sewage disposal
- Thermal pollution
- Noise pollution
- Particulate matter
- Pollution monitoring and surveillance systems

6.1.1 Air Pollution

The Air pollutants from the proposed CCGT are:

- Sulphur dioxide in flue gas

  The proposed power plant would use natural gas (NG), which does not contain any sulphur. Hence, there would not be any emission of sulphur dioxide in the flue gas.

- Nitrogen oxides in flue gas

  The plant will be utilizing Dry Low NOx / equivalent burners to minimize the NOx emission to a level less than stipulation by CPCB.

- Suspended Particulate Matter (SPM)

  The fuel used is filtered in multi stages and hence the flue gas will not contain any particulate matter.

6.1.2 Water Pollution

Steam Generator Blowdown

The salient characteristics of the Blowdown water from the point of view of pollution are the pH and temperature of water since suspended solids are negligible. The pH would be in the range of 9.5 to 10.3 and the temperature of the Blowdown water would not be above 100°C as it is flashed to atmospheric pressure. The quantity of blow down from both HRSG is approximately 33 m^3/hr. It is proposed to lead the HRSG blowdown water to blowdown sump and after mixing with Cooling tower blowdown the temperature would practically reduce to the ambient value.

DM plant Effluents

Hydrochloric acid and caustic soda would be used as regenerants in the proposed water treatment plant. The acid and alkali effluents generated during the backwash, rinsing and regeneration process of the DM plant would be drained into the neutralizing pit. The effluent would be neutralized by the addition of either acid or alkali to achieve the required pH. The effluent would then be pumped to Central monitoring basin.

Effluent for Horticulture

The following effluent water will be collected in a central monitoring basin.

- Water from Oil Water Separator
- Effluent discharge from Neutralising pit (TDS < 1000)

From the central monitoring basin, the effluent will be pumped out and used for horticulture within the plant. If required, Cooling Tower blow down will be mixed with for dilution. The effluent discharged on land for horticulture will meet the requirement of IS 3307.

Effluent Disposal to River

The Cooling Tower blow down (TDS < 500) will be led to led to HRSG Blowdown sump and after mixing with HRSG Blowdown, the effluent will be discharged into the river by 2 x 100% Blowdown pumps. Expected TDS of the effluent is 600 mg/l which is less than the max. allowable TDS Of 2100 for disposal in surface water. As far as the constituents of the TDS are concerned, Sulfates and chlorides will be less than 100mg/l, which is well within the max. allowable limit of 1000 mg/l each. The SS will be less than 100 mg/l. The pH will be around 7.5.

The COD and BOD will be less than 50 mg/l and 15 mg/l respectively against the respective max. allowable limit of 250 and 30 mg/l. The temperature of the effluent discharged to the river will be 35ºC, which is well within the max. allowable limit of 40ºC.

6.1.3 Sewage Disposal

Sewage from the plant would be conveyed through closed drains to septic tanks.

6.1.4 Noise Pollution

All equipment in the power plant would be designed/operated to have a noise level not exceeding 85 to 90 dBA as per the requirement of Occupational Safety and Health Administration Standard (OSHA).

In addition, since most of the noise generating equipment would be in closed structures, the noise transmitted outside would be still lower.

6.1.5 Pollution Monitoring and Surveillance System

For thermal power stations, the Indian Emission Regulations dated July 1984 stipulate the limits for particulate matter emission and minimum stack heights to be maintained for keeping the sulphur dioxide levels in the ambient within the air quality standards.

The characteristics of the effluent from the plant would be maintained so as to meet the requirements of the Central Pollution Control Board and the Minimum National Standards for Thermal Power Plants stipulated by the Central Board for Prevention and Control of Water Pollution.

6.2 Impact of Pollution/Environmental Disturbance

Since the fuel used is clean Natural Gas and DLN burners are used, there will not be any air pollution. As further necessary treatment of liquid effluents would be carried out, there would be no adverse impact on either air or water quality in and around the power station site on account of installation of the proposed plant.

6.3 Green Belt

A green belt of required width will be provided all around the plant boundary limits. In addition, avenue trees will be planted all along the roads.

7. Project Financials

7.1 Basis of estimates

The estimated project cost has been worked out on the following basis and assumptions:

- The project cost has been estimated based on the guidelines indicated by Government of India, Ministry of Power from time to time.

- Fuel: Natural gas is considered to be main fuel. In the present study gas with calorific value as 9500 kCal/SM^3 has been considered. HSD has been considered as emergency back-up fuel.

- Electrical System: 400 kV switchyard for evacuation of power has been considered in the present cost estimate. Cost of transmission line for distribution has not been considered in the project cost.

- Environmental:

  Stack emission: 70 M high main stack for each HRSG with online gas monitoring system has been considered.

  Effluent: The main effluent from the station would be cooling tower blow down, DM plant regeneration effluent. The effluent water after necessary treatment would be conveyed to the central monitoring basin. Waste water would, however, be reused as far as practicable.

- Time Schedule:

  Commissioning of Phase-I : 30 months from zero date
  (Around 700 MW Capacity)

  Commissioning of Phase-II : 36 months from zero date
  (Additional 700 MW Capacity)

Commissioning of Phase-III (Additional 700 MW Capacity)	:	42 months from zero date

7.2 Project Cost Estimate

A Preliminary cost estimate showing cost under major heads for the various alternatives has been furnished under Table 6.1 enclosed. The total project cost has been estimated as per following.

		Rs. (Million)
Capital Cost	:	53,557.66
Interest during Construction	:	6,109.27
Margin Money for WC	:	1,060.10
Total Project Cost	**:**	**60,727.04**

7.3 Estimation of Cost of Generation

The main objective of this sub-section would be to estimate and analyse the capital cost of the project so as to be in a position to estimate the Cost of Generation.

The major assumptions are as follows:-

i) Debt Equity Ratio : 70:30.

ii) The Construction period : 42 months

iii) Interest on term loan has been considered as 10% with 12 years of Repayment period after complete commissioning of the Plant.

iv) Pre-tax Return on equity has been considered as 16 % as per CERC guidelines.

v) Working capital has been estimated based as follows:

a)	Fuel Cost	:	1.0 month
b)	Debtors	:	2 months
c)	O&M Cost	:	1.0 month
d)	Margin Money	:	10%
e)	Rate of Interest	:	12.75%
f)	Maintenance spares	:	1% of the cost escalated @ 6% per year

vi) Auxiliary power consumption of the plant is 3% as per CERC guide line.

vii) Plant availability factor : 85% as per CERC guide line.

viii) O&M expenses have been considered as Rs. 14.80 lakh/MW (2009-10) with 4% escalation per year.

ix) Income tax holiday of 10 years out of 15 years U/S 80 IA if IT Act, has been considered from 6^{th} to 15^{th} year of operations.

x) Capacity of power plant has been considered as 2237.70 MW based on site rating of GE machines.

xi) The plant gross heat rate has been considered as 1850 Kcal/Kwh as per CERC guide line.

xii) Depreciation has been considered at an average rate of 4.816% per year based on equipment-wise rates specified as per CERC guideline.

xiii) The calorific value of gas has been considered as 8147 Kcal/SM^3.

xiv) The cost of gas has been considered as US $ 6.50 per MMBTU (Rs. 8.616/sm^3). No escalation in basic cost gas has been considered in terms of US $ /MMBTU. However, the inflation of exchange rate has been considered.

xv) The exchange rate has been considered as US $ 1.0 = Rs. 48.0.

Based on the above assumptions, cost of generation and other details have been estimated and the first year cost of generation is Rs. 2.91/Kwhr.

7.4 Sensitivity Analysis

The cost of generation varies with change in fuel cost and also change in capital cost. A sensitivity analysis has been carried out considering fuel costs as US $ 6.0/mmbtu and US $ 7.0/mmbtu. The results of sensitivity analysis in terms of first year tariff are tabulated below.

ITEM OF	FIRST YEAR TARIFF
Fuel Cost US $ 6.0/MMBTU	Rs. 2.75/KWH
Fuel Cost US $ 6.5/MMBTU	Rs. 2.91/KWH
Fuel Cost US $ 7.0/MMBTU	Rs. 3.07/KWH

8. Operating Framework

8.1 Method of implementing the Project

The project will be implemented through Tariff based bidding based on the Competitive bidding guidelines issued by Ministry of Power, Govt. of India. Power Company of Karnataka Limited (PCKL) will be carrying out the Project development activities and the bid process management.

PCKL will also be responsible for facilitating the land acquisition process in collaboration with Karnataka Industrial Areas Development Board (KIADB) and for obtaining approval from Ministry of Environment & Forest (MoEF) for environmental clearance. PCKL will also arrange for the Gas Supply & Purchase Agreement (GSPA) between the developer and M/s GAIL along with the water linkage for the project. PCKL will facilitate Power Purchase agreement (PPA) between the project company and Off-takers. Once the project is awarded to a Project Developer, the Project Developer will take overall responsibility for timely project execution and manage the subsequent operation and maintenance of the power station/plant.

8.2 Project Implementation Schedule

Successful execution of the project largely depends on the co-ordinated approach of the project implementing agencies. Proper co-ordination between the various project execution agencies, monitoring of project schedules, appropriate mobilization of manpower and other resources can achieve effective cost control and timely completion of the project.

The plant will be set up in three blocks of about 700 MW capacity each. Each block would either consist of one module of 2 + 2 + 1 configuration, or 2 modules of 1+1+1 (single shaft) configuration. With the 2 + 2 + 1 configuration, the Ist block planned to be implemented in 30 months and successive blocks at an interval of 6 months.

The broad time frame for implementation of the project would be as follows:

Block-1	:	30 months from the date of order.
Block-2	:	36 months from the date of order.

Block-3 : 42 months from the date of order.

In case 1+1+1 module configuration with single-shaft option is selected, it may be possible to advance the above time schedule by approximately 3 months.

It is envisaged that the whole procurement be done with single point responsibility under one turnkey EPC contract, with fixed contract price and time schedule with liquidated damage.

8.3 Risks & Mitigations

As projects are exposed to a wide variety of risks in the various stages of project evolution, risks associated with the development and commissioning of the project were identified, categorized and measures for risk mitigation defined as far as feasible.

Main categories of risks are

- Design risks
- Project related
- Construction related
- Operations related
- Revenue risks
- Financial risks
- Force majeure risks
- Insurance risks
- Environmental risks

The proposed mitigation measures shall be a basis for development of adequate strategies in the contractual framework of the tendering documents and later in the contracts with the construction contractors, subcontractors and in the O&M contractual documents. Some measures may also require frameworks in the agreements with the consumer.

The results of the preliminary assessment listed according to the type of risk are shown below

Risk Type	Risk Event	Risk Mitigation
Design Related	Design risk/ faulty design	Sound supervision at EPC stage with provision for remedy and liquidated damages from EPC contractors for curing the risk along with coverage from insurance
Project Related	Delay/non receipt of environmental and other statutory approvals	Proactive consultation and negotiation with authorities and other stakeholders
Project Related	Delay in land acquisition	Early negotiation with the site owners and other stakeholders.
Project Related	Project target cost estimate inadequate (PTC)	Open book approach, proactive activity with contractors
Project Related	Delay caused by governmental action or inaction / Force Majeure	Efforts to proactively act to acquire required approvals
Construction Related	Contractor Capability	Sound pre-selection process for the award of the project development contracts to contractors with experience, reputation and track record. Additional contractual safeguards like liquidated damages for non performance, performance security, defects liability clause etc
Construction Related	Suitability and availability of land	Field investigation studies to establish suitability. Land to be made available as condition precedent.
Construction Related	Cost overrun	Provide for reasonable cost overrun in fixed lump sum price in the construction contract. Any overrun on account of contractors to be absorbed by EPC contractors
Construction Related	Delay in construction	Safety clauses in EPC contract including liquidated damages from the contractor (sufficient to cover interest

		due to lenders and fixed operating costs)
Construction Related	Delay in establishment of power evacuation infrastructure	Foresee and plan in advance jointly with electricity boards and other power transmission companies involved
Operations Related	Failure to meet performance criteria at completion tests due to quality shortfall and defects in construction	Include planned redundancy in process design
Operations related	Failure of plant to meet performance criteria at completion tests	Require liquidated damages payable by the construction consortium, supplemented by insurance.
Operations related	industrial action such as strike, lockouts, work-to-rules blockades, go-slow actions	Establish sound industrial relations and also put in place insurance cover for loss or physical damage as well as for business interruption
Operations related	Operator failure.	Sound pre-selection process for the award of the operator contracts to contractors with experience, reputation and track record. Additional contractual safeguards like liquidated damages for non performance, performance security, defects liability clause etc
Operations related	River water suitability and deterioration of quality during the lifetime of the plant	Conservative design and ongoing water analysis during development and design phase. Threshold for River water quality parameter shall be determined providing certain tolerance from the existing River water pollution level.
Revenue Risk	Low offtake	Fixed capacity charge on take or pay principle to cover fixed costs like maintenance cost, debt servicing etc.
Revenue Risk	Rising fuel and other input costs	Long term fuel supply agreement / input cost recovery on actuals for quantity delivered
Revenue Risk	Exchange rate variation. Devaluation of local currency, fluctuations in foreign currencies.	Judicious mix of rupee and forex debts to optimize on interest cost. Protection against adverse currency

		movement by exchange cover, swapping of rupee debt etc.
Revenue Risk	Fluctuations in interest rates	Same as above (for hedging facilities against exchange rate risks).
Force majeure risk	Flood, earthquake, riot, strike	Insurance cover for loss or physical damage as well as business interruption
Force majeure risk	Changes in tax law, customs practices, environmental standards	Timely approvals/certification by statutory authorities
Insurance risk	Uninsured loss or damage to project facilities.	Insure against all the main risks.
Environmental risk	Environmental incidents due to Operator's fault	Require indemnity from the operator.