Prepared for:
**USAID-SARI/Energy Program**
**www.sari-energy.org**

# Regional Gas Assessment

Nexant

**Revised March 2003**

**For**

**United States Agency for International Development**

**Under**

**South Asia Regional Initiative for Energy**

**Prepared by**

**Nexant SARI/Energy**

# Contents

## 1.1 Introduction

The South Asia region is modestly blessed with gas resources, with the only major gas fields located in India, Bangladesh and Pakistan. The total estimated reserves in South Asia (India, Bangladesh and Pakistan) are around 1,900 billion cubic metres (bcm), slightly over **1%** of the total world's reserves.

Table 1-1 Gas Reserves in South Asia

| Country | Estimate of proven reserves (bcm) |
|---|---|
| India | 880 (31 tcf) |
| Bangladesh | 300 (11 tcf) |
| Pakistan | 710 (25 tcf) |

Source: BP 2002 (Estimates of recent Indian gas discoveries added)

***The consumption of natural gas in the South Asia region has grown substantially over the last decade***

The use of natural gas in the South Asia region has grown substantially over the last decade as indigenous sources of gas have been exploited, with substitution of liquid fuels by gas, both on grounds of cost and environmental benefit. The principal natural gas consumers have been India, Bangladesh and Pakistan, based upon the exploitation of their own indigenous natural gas resources.

The supply of natural gas in India has grown over the last two decades to around 28 bcm. Although depletion in the large fields currently under operation is likely to lead to a drop in production, recent finds in the Krishna-Godavari Basin are likely to make up this deficit. In Bangladesh, production was 11.1 bcm in 2002, and as fields are still being proved up, the potential production levels are anticipated to increase substantially.

***…and it is expected to continue to grow, provided solutions are found for the lack of infrastructure and the absence of a favourable institutional and commercial environment.***

The regional demand for natural gas continues to grow, with some forecasts showing gas demand in India quadrupling from current levels over the next 10 years. The demand in India is such that the country is planning to use other sources of gas supply from within and outside the region to meet the burgeoning demand. Demand in Bangladesh is constrained not by supply, but by lack of infrastructure and the absence of a favourable institutional/legal/commercial environment to develop/expand local markets. Given Bangladesh's potential gas reserves base, there will still be potential for gas exports even after planned development of the local markets. Sri Lanka is seeking cleaner fuels for power stations and gas would be a suitable option if competitively priced gas supplies could be made available.

Major gas fields surround the region and there have been several regional projects proposed to bring gas to South Asia from other sources in neighbouring countries, notably gas pipelines from Iran, Burma and Turkmenistan along with LNG projects bringing gas from SE Asia and the Arabian Gulf.

*It is critical to understand the potential for establishing a viable gas market in the region.*

Understanding the regional gas supply situation and the potential for establishing viable gas markets is crucial to policy development in the region. It is critical that the regional natural gas supplies are exploited most efficiently and will be economically beneficial for all parties. This could avoid or at least delay the need for very expensive inter-regional gas infrastructure.

## 1.2 Bangladesh

*In Bangladesh gas has a high share of the total energy consumption but very low per capita consumption.*

In Bangladesh natural gas comprises **47%** of the total energy consumption, although despite this dominance the per capita consumption of gas is amongst the lowest in the world.

The gas sector in Bangladesh is controlled by the state-owned company Petrobangla, which has historically been responsible for the exploration, production, transmission and marketing of gas. The last decade has seen the introduction of international oil companies into the exploration and production sector, principally Unocal and Cairn/Shell

Gas production in Bangladesh began in the 1960 from the Chattak field and has risen steadily over the past four decades. Production in 2002 was 391.6 bcf (11.1 bcm). Production is presently predominantly from the Titas and Habiganj fields operated by Petrobangla (around **55%** of 2002 production) and the Khalastila and offshore Sangu fields operated by Unocal and Cairn/Shell respectively (around **20%** of 2002 production). The gas produced by the independent companies is transported and marketed by Petrobangla.

Table 1-2 Bangladeshi Gas Production in 2002

| Producing Field | 2002 Production (billion cubic feet) | 2002 Production (million cubic metres) |
|---|---|---|
| Titas | 127.8 | 3,617 |
| Habiganj | 86.1 | 2,437 |
| Bakhrabad | 12.6 | 357 |
| Narsingdi | 5.6 | 159 |
| Meghna | 3.4 | 96 |
| Salda | 5.4 | 154 |
| Sylhet | 1.9 | 53 |
| Kailashtila | 27.6 | 781 |
| Rashidpur | 37.4 | 1,058 |
| B'Bazar | 4.8 | 135 |
| Sangu | 48.7 | 1,380 |
| Jalalabad | 30.4 | 860 |
| **Total** | **391.6** | **11,088** |

Source: Petrobangla

***Gas pricing differentials exist between producers, with subsidies to some consumers.***

Gas pricing in Bangladesh is low by international standards, which reflects in part relatively low production costs but more particularly direct subsidies to consuming sectors through gas prices. Petrobangla has negotiated production-sharing contracts with the international oil companies, with pricing linked to fuel oil prices posted in Singapore. This has effectively made the gas produced by the international companies more expensive than the gas produced by Petrobangla and generally higher than the price that Petrobangla is selling gas to its customers. This has led to reluctance from Petrobangla to purchase gas from the international companies, preferring to maximise production from its own fields.

The principal demand for natural gas in Bangladesh comes from power generation and fertiliser production.

Table 1-3 Bangladesh Gas Consumption in 2000

| Sector | Consumption (mcm) | Proportion of total |
|---|---|---|
| Power | 4,162 | **64%** |
| Fertiliser | 2,374 | **37%** |
| Industry | 1,536 | **24%** |
| Domestic & Commercial | 1,201 | **19%** |
| **Total** | **6,480** | **100%** |

Source: Petrobangla 2000

***Demand for gas may be overstated due to gas prices below international levels.***

Gas demand has risen very substantially over the last two decades, growing at up to **10%** per annum, albeit from a very low base. Demand is forecasted to continue rising significantly with growth rates of around **6%** over the next decade. The interrelationship of demand forecasts and pricing is problematic, as the demand forecasts do not consider the demand for gas at international prices (such as those received by the international oil company producers). The existing demand forecasts for gas could be considerably constrained as prices move towards international price structures.

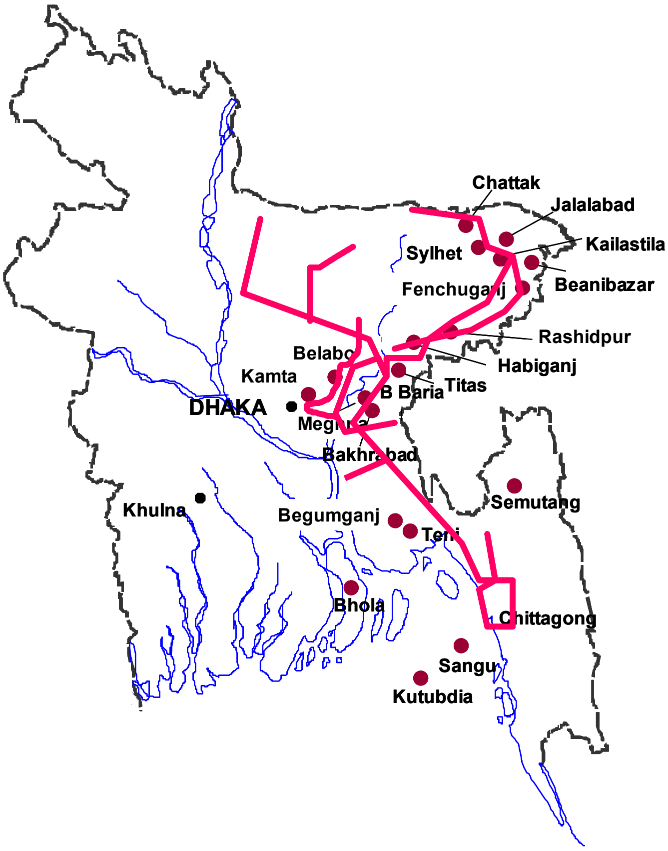



Figure 1-1 Gas Fields and Infrastructure in Bangladesh

The gas transportation system in Bangladesh links the fields in the north east of the country to Dhaka, the producing areas in the south east of the country and Chittagong. There is a recently completed connection across the Jamuna River bridge which is to be further extended on the western side of the country. There are a number of bottlenecks in the existing system and expansion will be required to meet increasing future demand.

The issue of existing gas reserves is highly contentious in Bangladesh. Numerous studies have been conducted over the last few years but have been hampered by a lack of detailed exploration data and limited production history data on older Petrobangla-operated fields. Several estimates put the existing proven net recoverable reserves at 10 –11 trillion cubic feet (tcf), but it is widely believed that the proven reserves could ultimately be in the range of 10-25 tcf, with some, notably international oil companies, indicating that the ultimate figure could be 40 tcf.

Official forecasts of supply and demand indicate that Bangladeshi demand will exceed supply by 2008. However, the demand projections are considered to be very optimistic and it is believed that Bangladesh has sufficient natural gas for at least 20 years and probably much longer. If recoverable reserves forecasts of 40 tcf prove to be true, Bangladesh would be able to meet even aggressive projected demand forecasts for at least 40 years.

***Current gas policy hinders possibilities for Bangladesh gas exports.***

To date, a policy of ensuring that Bangladesh has enough reserves to cover 50 years of domestic demand is in place. This policy has frustrated export plans for the supply of gas by pipeline to India, drafted by the international companies who are seeking to maximise production from the investments they have made in developing the fields in Bangladesh.

## 1.3 India

Natural Gas consumption in India has grown significantly in recent years, although at present it represents only **13%** of current primary energy consumption.

***The Indian gas sector is dominated by public sector enterprises.***

The gas supply sector in India is dominated by public sector enterprises under the administrative control of the Ministry of Petroleum. Until recent years, all oil and gas in India was produced by the Oil and Natural Gas Corporation (ONGC), and Oil India Limited (OIL). These two companies undertook all exploration and production (E&P) activities. ONGC has been the dominant company, accounting for over **90%** of production. Gas transmission comes under the authority of the Gas Authority of India Ltd (GAIL), which was established in 1984.

In 1994 the Government awarded the first joint venture (JV) fields and currently 18 fields, mostly small, are operated by joint ventures and private companies. The state-owned companies are shareholders in JV's for medium sized fields, although there is no participation in small sized fields.

***63% of India's total gas production is generated by the western offshore fields.***

The current output is concentrated on the western offshore fields, which produced 17.74 bcm of the total 28.45 bcm of gas produced in 1999/2000, amounting to **63%.** Production from other regions is relatively low, with the exception of the north eastern areas. In this region, and particularly in Assam, production has in the past been restrained by a lack of investment in supporting infrastructure, although now all produced gas is utilised.

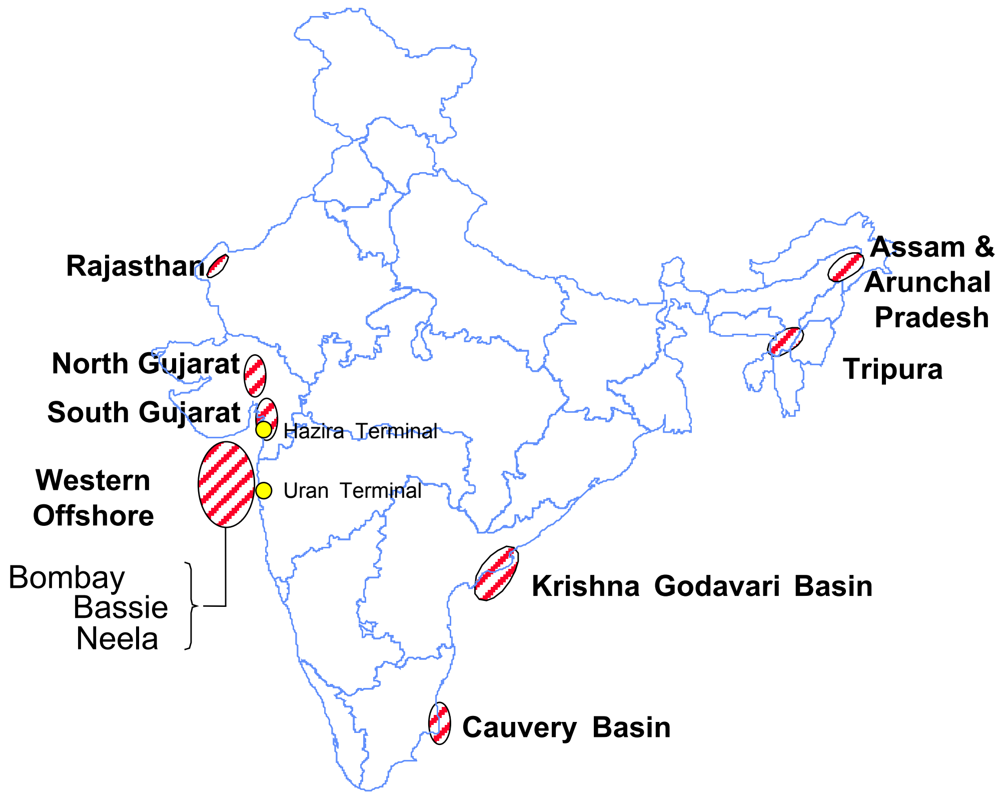



Figure 1-2 Principal Gas Producing Regions of India

***India has low reserves of life and major gas fields are in decline.***

The overall reserves life for India has been in decline since the early 1980's and at present is under 31 years of current production. The largest producing fields, the Bombay High field (associated) and Bassein field (free gas), which combined currently provide almost **60%** of total gas production, are both in decline, as is production from the North and South Gujarat fields. The gross production figures for 1999/2000 were as follows:

Table 1-4 Gross Indian Gas Production for 1999/2000(billion cubic metres)

| Onshore | Production (billion cm) |
|---|---|
| Gujarat | 3.10 |
| Assam/Nagaland | 2.08 |
| Arunachal Pradesh | 0.02 |
| Tripura | 0.35 |
| Tamil Nadu | 0.14 |
| Andhra Pradesh | 1.36 |
| Rajasthan | 0.15 |
| **Total** | **7.21** |
| **Offshore** | |
| ONGC | 17.74 |
| Private/Joint Venture companies | 3.47 |
| **Total** | **21.21** |
| **Grand total** | **28.45** |

Source: TERI Energy Data Directory 2001/2002

***The prospects of large increases in overall production are low.***

The western onshore and offshore regions have been extensively explored and there is no indication of major new gas plays, although there may be opportunities for increasing production from some existing fields. Estimated reserves of 7 tcf have recently been discovered in the Krishna-Godavari basin, with speculation that further significant deposits could be discovered in the region. It is expected that these discoveries will be able to maintain current supply levels in the face of falling production from the more mature fields. There is also considerable potential to develop supply from the north-eastern region, principally Assam and Tripura, and there is a ready demand for this gas. The difficult political situation has impeded development in this area.

It was hoped that a new exploration policy would stimulate greater interest in the Indian Exploration and Production (E&P) sector from the international oil industry, although interest to date has only been moderate.

Along with the recent Krishna-Godavari discoveries, other areas of reasonable prospectivity are believed to be in deepwater off the south-west and east coasts, coupled with opportunities to exploit coalbed methane in coal producing areas.

Gas demand in India is predominantly from power generation and fertiliser production, which makes up **75%** of the total consumption.

Table 1-5 Natural Gas Consumption in India for 2000

| Industry | Consumption (million cm) | Proportion of the total (%) |
|---|---|---|
| Power generation | 9,143 | **38%** |
| Industrial fuel | 2,502 | **11%** |
| Tea plantation | 147 | **1%** |
| Domestic fuel | 257 | **1%** |
| Captive use/Liquefied petroleum gas | 900 | **4%** |
| Fertiliser industry | 8,917 | **37%** |
| Petrochemicals | 686 | **3%** |
| Others | 1,254 | **5%** |
| **Grand Total** | **23,806** | |

Source: TERI Energy Data Directory 2000/2001

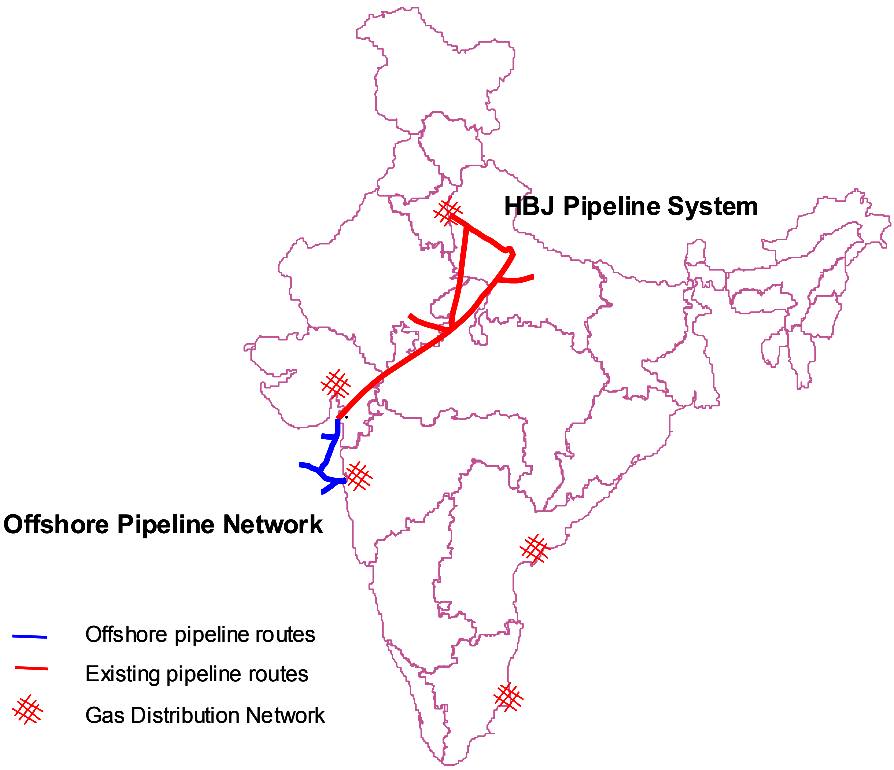
Existing demand projections conducted by GAIL, and based on current gas prices, show gas demand reaching 104 bcm by 2009 and 198 bcm by 2020, which is principally driven by the pressing need for more power generation plant. The liberalisation of gas prices may result in these levels of demand changing as the impact of the move towards market levels of gas prices is felt. The ADB sponsored India Gas Development Master Plan indicates that when price sensitivity is incorporated into the demand picture the demand for gas will be around 92 bcm by 2011. The incremental demand, particularly in the 2002-2007 period, will be primarily in the west and north west of India in Maharashtra, Gujarat, and along the HBJ pipeline corridor

*The growth in gas demand over the next five years is expected in the west and northwest of India.*

to the Delhi region. The projected gas deficit in India will have to be met through gas imports.

It is certain that the projected demand for gas is significantly greater than the projected supply and at least in the short to medium-term, that any significant expansion in demand will have to be met through imports of gas. Such imports, whether in the form of LNG or pipelines, will require anchor customers able to support such projects. The only customers in India who will be able to provide this support are the power sector and other major industrial consumers (e.g. fertiliser plants, although there is considerable doubt that the fertiliser sector could support substantially higher gas prices.).

Currently in India, gas infrastructure exists for production and transportation of about 90 MMcm/day of gas and the transmission and distribution of about 65-70 MMcm/day. Most of the infrastructure is installed in the west and north west of India for the transportation of gas to shore from the western offshore fields and the transmission of this gas to end users. By far the largest of the transmission systems is the HBJ line, which takes gas from Hazira to Delhi, Gujarat, Madhaya Pradesh, Uttar




Pradesh and Rajasthan.

Figure 1-3 Gas Infrastructure in India

There are around 3,700 km of gas pipeline laid offshore in India, of which almost 1,000 km are gas trunkline networks. The western offshore region contains most of India's production infrastructure and these fields supply the Uran and Hazira terminals.

***Pricing issues between competing fields are critical in the economics of the proposed LNG projects.***

The basic consumer price for gas produced by ONGC and OIL in India is set against a basket of fuel oils. The exception is gas produced in the north east, which sells at **45%** of the basket of fuel oils price. The producers are compensated by payments from the Gas Pool Account. ONGC/OIL and joint venture operations are permitted to sell gas from marginal isolated fields to be developed in future at prices that will be market driven. The producer price realised for gas from the western offshore Tapti field has been reported as $3.11/MMBTU. The cost of transportation on the HBJ pipeline is a postage stamp tariff of approximately $1/MMBTU.

There are, at present, two projects under development to deliver liquefied natural gas (LNG) to the west coast of India. The first, a 4.7 MTPA project (approximately 6.4 bcm) at Dabhol in Maharastra, has been almost completed but is now stalled due to the collapse of Enron. The second, presently under construction, is located at Dahej in Gujarat and will supply the Gujarat vicinity and the HBJ transmission line with 5 MTPA of LNG (approximately 6.8 bcm) from Qatar. A third project, promoted by Shell, is at an advanced stage of planning for the development of an LNG import terminal at Hazira also in the state of Gujarat. Regasified LNG will be delivered into India at around $3/MMBTU, which will provide a number of pricing challenges in relation to the substantially cheaper indigenous gas.

## 1.4 Sri Lanka

***Limited domestic gas resources, distance from regional supply sources and low demand make traditional gas projects uneconomic in Sri Lanka.***

Sri Lanka has no indigenous gas resources and is distant from regional sources of supply. The projected demand build up for gas from Sri Lanka is well below the level required to make traditional gas projects viable, both pipeline and LNG.

However, recent technological developments may have the potential to provide gas at economic prices, namely smaller-scale LNG projects and the supply of gas in compressed form by ship. In addition, there is the possibility of utilising regional gas sources via offshore pipelines from India. Each of these options is currently being analysed in a parallel study.

## 1.5 Intra SARI Regional Gas Opportunities

***The key intra regional opportunity is a pipeline project supplying India from Bangladesh.***

The key intra-regional opportunity is a potential pipeline project supplying to India from Bangladesh. This project would marry the potential surplus of gas in Bangladesh to the growing deficit in India. There are a number of obstacles to this project both physical and political. The bulk of the gas resources in Bangladesh are in the east of country, while the major market areas in India, at least in the short to medium-term, are in the north and west of the country. In order to reach a sufficiently large market, the pipeline would have to travel some 2,000 km in length across India. The capital costs of such a project would be substantial. In targeting these Western India markets, such a project would be competing with the LNG projects that are already under development. Demand is likely to grow in the eastern parts of India but will be in competition with cheap coal in north eastern areas close to Bangladesh, and the level of demand in the short to medium-term would not be sufficient to justify the project expenditure.

The key non-technical issues would be the resolution of inter-governmental, political and trade relationships, as well as addressing the issue of gas security/appropriate reserve levels in Bangladesh.

***…but significant technical, political, trade, security of supply and economic issues have to be addressed.***

The critical issue relating to the import of gas from Bangladesh is the availability of reserves and the willingness of the Government of Bangladesh/Petrobangla to make reserves available for export projects. A large pipeline project of 27.4 MMcm/day would require dedicated reserves of at least 240 bcm (8.6 tcf). Given the existing mindset of the Government of Bangladesh there will need to be significant new gas discoveries before reserves of this magnitude are set aside for export projects to India. Thus timing becomes an important issue. The latest exploration round in Bangladesh has been executed, although a major discovery is likely to take several years to prove up and the development of a pipeline project at least two more years. Therefore, if the existing reserves criteria continue to be the governing metric, any gas export project from Bangladesh is not likely to commissioned before at least 2005, and possibly much later.

## 1.6 Gas Imports into the SARI Region

***Significant gas reserves in countries adjacent to South Asia could be utilised to meet the demand in the SARI region.***

There are significant gas reserves in countries adjacent to South Asia that could be utilised to meet the import requirements indicated by the supply shortfall. These reserves are principally in the Middle East, notably Iran and Qatar, in Turkmenistan in Central Asia, and in South East Asia, in particular Indonesia, Malaysia and Australia. Bangladesh has had significant recent gas finds and could be a potential exporter to India. Myanmar is also a potential exporter to South Asia.

Table 1-6 Proven Reserves of Major Gas Producing Countries in Asia and the Middle East

| Country | Proven Reserves (Bcm) | R/P Ratio (Years) |
|---|---|---|
| Iran | 23,000 | >100 |
| Qatar | 14,400 | >100 |
| Abu Dhabi | 6,010 | >100 |
| Turkmenistan | 2,860 | 57 |
| Indonesia | 2,620 | 42 |
| Australia | 2,550 | 78 |
| Malaysia | 2,120 | 45 |
| India | 880 | 31 |
| Oman | 830 | 62 |
| Bangladesh | 300 | 33 |

Source BP 2002, NEXANT

Gas sources in Turkmenistan and Iran are relatively under-exploited, mainly due to political difficulties and lack of gas export infrastructure. Other sources, such as Qatar, have only opened up to international markets relatively recently.

***The economic attractiveness of one form of import over another has to be established.***

The economic attractiveness of one form of import over another depends on many factors. The keys to which is the distance to the end user and the price charged for gas into a pipeline or LNG liquefaction plant. For a pipeline project, the transit tariff or fee that may be levied in intermediate countries will be a critical factor. Typically pipelines are more economical over shorter distances (1,500 km off shore - 3,000 km onshore, depending on the volumes transported) and LNG more advantageous over greater distances.

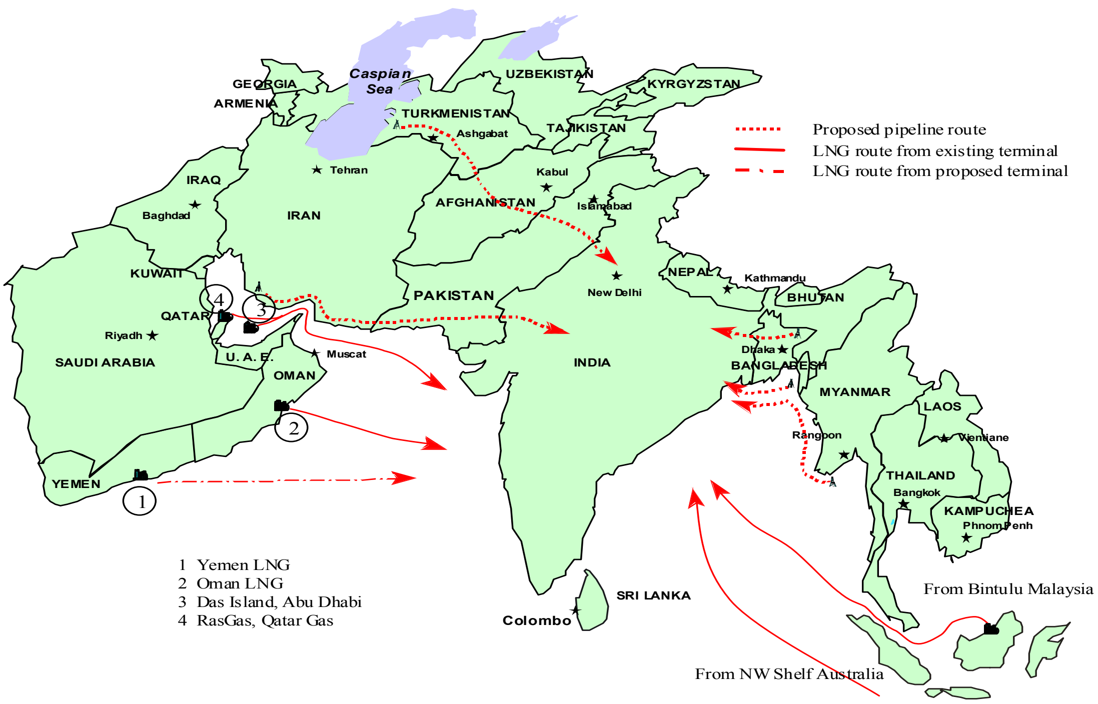



Figure 1-4 Principal Gas Import Routes to South Asia

The major pipeline projects with the potential to bring gas to India are from Iran through Pakistan. An onshore pipeline from Iran could supply gas most efficiently to the north west region. The major problems with the Iranian project are the thorny political relationships between India, Pakistan and Iran, the attendant concerns over security of supply and the current US sanctions imposed on investment in Iran, which act as a curb on international and multilateral support. The supply of gas by pipeline from Turkmenistan remains a long-term option, although the difficulties inherent in transit of gas through Afghanistan and Pakistan, and the uncertainties relating to rule of law in Afghanistan are likely to make such a project unfinanceable for some significant time to come.

Nexant analyses indicate that large volumes of gas could be transported to India from Iran in the range \$2/MMBTU in economic terms, although this takes no account of the economic rent required by the resource owner, input prices and levies from transit countries. Assuming a price of \$1.5/MMBTU, covering gas purchase and intermediate tariffs, this would give a delivered price of gas in North-West India competitive with LNG. Gas supplied via pipeline from Myanmar is unlikely to be competitive into the SARI market due to the long distances to potential markets.

***LNG from the Middle East could be the best source of imported gas for West and South India.***

LNG supplied from the Middle East would be the best source of imported gas for the western coast and south of India. On the eastern coast LNG is likely to be equally competitive with pipeline gas from Bangladesh. The enormous gas reserves in Qatar are already being developed for use by LNG projects and Qatar has the reserve base to supply the volumes that will be required in India.

Oman is the closest LNG producer to India, although there is some question as to whether Oman has sufficient gas reserves available to support further LNG projects. Iran could exploit offshore gas fields for LNG, the delivered cost of which would be similar to that from Qatar. Currently Iran has 4 LNG projects in the planning stage, although it remains to be seen how many of these would find financing. India is a key target market for these developments.

LNG from Malaysia would be as competitive on the east coast as supplies from the Gulf. However, the reserves in Malaysian fields are already heavily exploited for LNG sales to Japan and Korea and it is uncertain that there would be sufficient reserves to support a project supplying India.

***The supply of LNG to India is possible under appropriate gas pricing structures.***

The supply of LNG to India at affordable prices is possible, but much will depend on the ability of India and LNG suppliers to negotiate an appropriate gas pricing structure. The present climate in the LNG market, where Far Eastern customers are struggling to take contracted quantities and the potential for incremental demand is very limited, is increasing the interest of suppliers to Indian markets. The use of competitive tendering will help India to hone the price of LNG offered.

***The development of anchor projects requires creditworthy power clients in India.***

The financing of both pipeline and LNG projects will be heavily dependent upon secure, long-term supply contracts. This is particularly so for a greenfield LNG project, which is significantly more capital-intensive. Import projects will require bankable guarantees on offtake contracts in order to raise the requisite finance. As the vast majority of future baseload demand to support such projects will come from the power sector, this will require bankable guarantees from the power producer, and where the power producer is not considered sufficiently creditworthy, the support of state or federal governments. In some cases the support from a multilateral agency such as the ADB will also be necessary.

### 1.7 Regional Gas Overview

There are significant gas reserves in countries adjacent to South Asia that could be utilised to meet the import requirements in the SARI countries. These reserves are primarily located in the Middle East, notably Iran and Qatar, in Turkmenistan in Central Asia and in South East Asia, in Indonesia, Malaysia and Australia. Within the SARI region, Bangladesh has had recent gas finds and could be an exporter to India.

The economic attractiveness of the two main forms of imported gas, i.e. LNG and pipelines, depends on many factors. The key factors are the distance to the gas end user and the price charged for gas into a pipeline or LNG liquefaction plant.

Typically pipelines are more economic over shorter distances: 1,500km offshore and 3,000 onshore, function of the volumes transported. LNG becomes more economic for grater distances.

The potential suppliers of LNG to the SARI region are either existing LNG terminals or greenfield projects. The main potential LNG suppliers are located in:

- Qatar: total capacity 14.3 million TPA
- Oman: total capacity 9.9 million TPA
- Abu Dhabi: total capacity 5.5 million TPA
- Yemen
- Iran
- Australia: total capacity 7.5 million TPA
- Indonesia: total capacity 34.3 million TPA
- Malaysia: total capacity 22.2 million TPA

There are also a number of import pipeline routes considered for servicing the Indian market. The most important ones are:

- Iran – Pakistan - India - onshore
- Iran – Pakistan - India offshore
- Bangladesh – India onshore
- Bangladesh – India offshore
- Turkmenistan – Afghanistan-Pakistan - India
- Oman – India deep water

Each of these projects has its own particular intrinsic technical difficulties. In addition, the Government of India has some difficulties in political relations with most of the supply/transit countries.

## 1.8 Summary

The SARI region is relatively poor in natural gas resources relative to both the landmass and population size. India has proven natural gas resources of 880 bcm and Bangladesh 300 bcm. At expected future production levels it is likely that India will exhaust existing reserves within the next 20 years.

***Growth of Bangladeshi gas reserves will require the involvement of international players.***

Although projections show Bangladesh going into gas deficit in 2008, the reality is that gas demand is highly unlikely to develop as projected, and it is likely that Bangladesh's current proven gas reserves will last at least 20 years providing domestic supply, and probably significantly longer. In addition, there is a very large upside potential for further growth of the reserves base, possibly up to 40 tcf. This will require additional exploration and investment work, the bulk of which is likely to come from international oil companies. Presently, this potential is being stymied by the inability of the existing international players to get their gas to market.

***Bangladesh could export to India to meet the demand deficit.***

The demand for gas in India is already well in excess of supply and this situation is set to continue as existing fields continue to deplete. The recent discoveries in the Krishna-Godavari Basin and the introduction of LNG into the west of India over the next few years will compensate for this depletion in production in the short-term. But further sources of gas will be required to meet India's needs in the medium and long-term. There is an opportunity for Bangladesh to monetize its gas assets by means of an import project to India. This faces political obstacles, in view of the Bangladeshi government's desire to keep the resources for domestic use, and also development challenges in the magnitude of a project that would be needed to get the gas to the distant North/West India markets.

The projected shortfalls in gas supply in the north western, western and southern regions of India will only be met in the short to medium-term by LNG supplies. In the longer-term, the supply of gas through (or around) Pakistan may become a possibility to support demand in the north west of the country. The projected supply shortfalls on the eastern side of India (in the medium to longer-term) could be met best by supply from Bangladesh if sufficient reserves are discovered and proved up, and the governments of Bangladesh and India are able to agree mutually acceptable terms.

***The Asian region has significant gas reserves that can meet the demand in the SARI region.***

The Asian region has substantial reserves of gas which could be imported into the SARI sub-region by pipelines or LNG. Pipelines would be viable from Iran or Turkmenistan, but there are enormous political challenges to be overcome in laying pipelines that cross Afghanistan and/or Pakistan. LNG supply to the SARI sub-region is attractive for Middle East suppliers, as the logistics are much more favourable than for the Far East markets. LNG projects continue to be planned in Middle East, most notably in Iran, although financing could be problematic.

The introduction of imported gas into the region will bring with it pricing dilemmas, as the cost of imported gas will be significantly higher than gas sold in the region at the present time. These pricing issues have yet to be resolved.

### 2.1 The SARI/Energy Project

The key strategic objective of the South Asia Regional Initiative Energy (SARI/Energy) project is to promote socially and environmentally sound economic growth through regional energy development and encourage the co-operation and eventual trade in energy resources amongst the countries of South Asia.

The development of natural gas usage and trade is a key element of the SARI/Energy initiative.

### 2.2 Natural Gas

Natural gas is a key fuel for the present and the future both globally and in the South Asia region. For many years natural gas in many parts of the world was seen as a marginal fuel as it requires considerable infrastructure to process and transport to markets either in pipelines or in other forms, such as liquefied natural gas (LNG). Gas was often considered a nuisance by-product of oil production, which was flared or re-injected. However, in the last 3-4 decades natural gas has become a key global fuel, accounting for **23%** of the world's primary energy mix. This development has been driven by several factors:

- Rising prices for oil products, in particular the oil shocks of the 1970's and 1980's.
- Developments in pipeline technology and liquefaction processes which have brought down unit transportation costs.
- Improvements in power generation technology, which with modern combined cycle gas turbine technology can reach thermal efficiencies of **55%** (by contrast, fuel oil steam turbine technology has a thermal efficiency of around **38%**).
- Increased environmental awareness of the benefits of burning gas rather than heavier fuels in respect of air emissions. Unlike other liquid hydrocarbon fuels and coal, gas has virtually no harmful $SO_2$ emissions.

***The increase of material gas usage in the South Asia region depends on the gas price delivered to end-users.***

Natural Gas is expected to be the fastest growing component of world energy consumption with an annual average growth of over **3%**. According to the International Energy Outlook published by US EIA, gas is projected to rise to **38%** of the global primary energy consumption by 2020, from **23%** in 1999.

The increased use of natural gas as an energy source in the South Asia region over other less environmentally environmental options, such as fuel oil and coal, will be attractive, provided that gas can be supplied at a reasonable price.

## 2.3 Gas in the SARI/Energy Region

The South Asia region is modestly blessed with gas resources, with the only major gas fields located in India, Bangladesh and Pakistan. The total estimated reserves in South Asia (India, Bangladesh and Pakistan) are around 1,900 billion cubic metres (bcm), slightly over **1%** of the world's total reserves.

Table 2-1 Gas Reserves in South Asia

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| Pakistan | 710 (25 tcf) |

Source: BP 2002 (Estimates of recent Indian gas discoveries added)

The use of natural gas in the South Asia region has grown substantially over the last decade as indigenous sources of gas have been exploited, with substitution of liquid fuels by gas, both on grounds of cost and environmental benefits. The principal natural gas consumer have been India, Bangladesh and Pakistan, based upon the exploitation of their own indigenous natural gas resources.

The supply of natural gas in India has grown over the last two decades to around 28 bcm. Although depletion in the large fields currently under operation is likely to lead to a drop in production, recent finds in the Krishna-Godavari Basin are likely to make up this deficit. In Bangladesh, production was 11.2 bcm in 2002, and as fields are still being proved up, the potential production levels are anticipated to increase substantially.

***India is planning to use a variety of domestic and foreign gas sources to meet growing demand.***

The regional demand for natural gas continues to grow, with some forecasts showing gas demand in India quadrupling from current levels over the next 10 years. The demand in India is such that the country is planning to use other sources of gas supplies from within and outside the region to meet the burgeoning demand. Demand in Bangladesh is constrained, not by supply, but by a lack of infrastructure and the absence of a favourable institutional/legal/commercial environment to develop/expand local markets. Given Bangladesh's potential gas reserves base, there will still be potential for gas exports even after the planned development of local markets. Sri Lanka is seeking cleaner fuel for power generation and gas would be a suitable option if competitively priced supplies can be made available.

***Demand in Bangladesh is constrained by the lack of infrastructure.***

Major gas fields surround the region and there have been several regional projects proposed to bring gas to South Asia from other sources in neighbouring countries, notably gas pipelines from Iran, Burma and Turkmenistan, along with LNG projects bringing gas from SE Asia and the Arabian Gulf.

## 3.1 Introduction

The petroleum geology of Bangladesh is that of a classic deltaic environment formed by the Ganges River draining into the Bay of Bengal. This is the most common form of petroleum reservoir environment in most of the large oil provinces. Other examples are the Gulf of Mexico, the Niger Delta, the Nile Delta, and North West Slope of Alaska. As such, the potential prospectively should be high. Due to the nature of the organic matter deposited, the complex geological deposition and the subsequent heating and pressure, Bangladesh is gas prone.

Significant gas finds were first established in Bangladesh during the 1950s in Haripur, in greater Sylhet region. However, little development at work was done until independence in the early 1970s when the new government started initiatives to bring in multinational companies to explore the region. The unstable political situation throughout the mid 1970s, when multinational operations were nationalised, and also situation in the early 1980s resulted in multinational companies abandoning exploration work, and the development of the sector has largely been in the hands of the state owned national oil company Petrobangla. At the present time, two multinational oil companies are present in Bangladesh.

In Bangladesh, natural gas comprises **47%** of the total energy consumption, although, despite this dominance the per capita consumption of gas is amongst the lowest in the world.

## 3.2 Gas Sector Organisation

The gas sector in Bangladesh is controlled by the state-owned company Petrobangla, which has historically been responsible for the exploration, production, transmission and marketing of gas. The last decade has seen the re-introduction of international oil companies into the exploration and production sector, principally Unocal and Cairn/Shell

***The gas sector is dominated by the state-owned company Petrobangla.***

Petrobangla was created in 1989 from its previous incarnation as the Bangladesh Oil, Gas and Mineral Corporation. Petrobangla, as such, is not active operationally. Its activities are essentially conducted through eight operating companies which it controls on the Government of Bangladesh's behalf. While Petrobangla is often referred to as a holding company, it is not required to produce consolidated accounts of the group as it does not own the operating companies, being only the custodian of their shares.

Petrobangla is a statutory body of the Government of Bangladesh, governed by 1985 ordinance, and is under the purview of the Ministry of Energy and Mineral Resources (MEMR). The operating companies, some of which originated with the nationalization of foreign oil companies, are now incorporated under the 1994 Companies Act as public limited companies. Petrobangla is governed by a nine-member board, including the chairman, all of whom are Government of Bangladesh appointees.

The operating companies are in principle governed by their respective Board of Directors, but their powers are limited, being subject to subsequent ratification by Petrobangla's board and, as the case may be, the Government of Bangladesh, which approves major decisions related to pricing, operating and development budgets, organizational setup, staffing and contract awards.

Transactions involving foreign oil companies are conducted through Petrobangla Petroleum Concessions Department (PCT), a specialized unit which also acts as their regulator and administrator. PCT has been particularly active in preparing the exploration tender rounds, as well as in carrying out the devaluation in the divestment process

***The natural gas policy, operation and regulation framework is driven by the Government of Bangladesh.***

The present framework is institutionally complex, and its main feature is that all matters, be they of a policy, operational, or regulatory nature, are decided ultimately by the Government of Bangladesh. Given the Government of Bangladesh's administrative burden, decisions are often delayed, and it is unclear whether they are dictated ultimately by political, commercial or other considerations.

Operations are conducted through the other following operating companies;

- **Exploration drilling**: the Bangladesh Petroleum Exploration Company Ltd (BAPEX) is in charge of the geological/geophysical surveys and drilling exploration wells. The company's operating revenue is a **4%** service charge levied on gas production. BAPEX has approximately 12,000 employees.

- **Gas Development & Production**: Bangladesh Gas Fields Company Ltd (BGCFL), formerly a subsidiary of Shell Oil, nationalized in 1975, is responsible for the operation of the central gas fields of Bakhrabad, Feni, Habiganj and Titas. Sylhet Gas Fields is responsible for the northern gas fields of Beani Bazar, Chattak, Kailastila, Rashidpur and Sylhet.

- **Transmission Distribution and Marketing**: Currently, three franchised operating companies of Petrobangla distribute and market natural gas: JGTDSL, TGTDCL and BGSL. Areas of transmission and distribution operation are defined and notified by the government. A fourth distribution company is anticipated to manage the Western Zone distribution system when developed in the future. These companies hold exclusive rights to transmit gas on a regional basis.

- **National Transmission System:** The Gas Transmission Company Ltd (GTCL), is responsible for the high-pressure national trunk system. GTCL's articles of association allow it to operate as a common carrier and permit it to form joint ventures with private partners, thereby facilitating equal pipeline access by private guest producers. However, because of indecision and delays in the transfer of the corresponding assets by the three transmission and distribution companies, GTCL currently only operates less than 20 percent of a high-pressure trunk network (300 km out of 1800 km). GTCL's source of revenue is the tariff levied on the distribution companies.

Major foreign energy companies active in gas exploration and development in Bangladesh include Shell and Unocal, who operate in Bangladesh through their wholly owned subsidiary, Unocal Bangladesh Ltd. In May 1999, Unocal took over the assets and operations in Bangladesh of Occidental, which had experienced a major explosion and fire at one of its wells in the Sylhet area in 1997.

## 3.3 Gas Production

Gas production in Bangladesh began in 1960 from the Chattak field in the north east of the country after the first gas finds were made at Sylhet in 1955 and Chattak in 1959.

Gas production has risen steadily over the past four decades to the current level of over 9 bcm per year. Over these past 4 decades, production from the fields of the north east has been dominant.

*50% of the gas production is generated by Petrobangla.*

In total there are 22 identified major gas fields in the country, of which 12 are currently producing. The largest producing fields are Titas and Habiganj. Titas is the largest producing field, accounting for **40%** of Bangladeshi natural gas production over the last decade, and in 2000 accounted for over **30%** of the total gas production. The Habiganj field in 2000 produced almost **20%** of the total gas production. Petrobangla operates both of these fields.

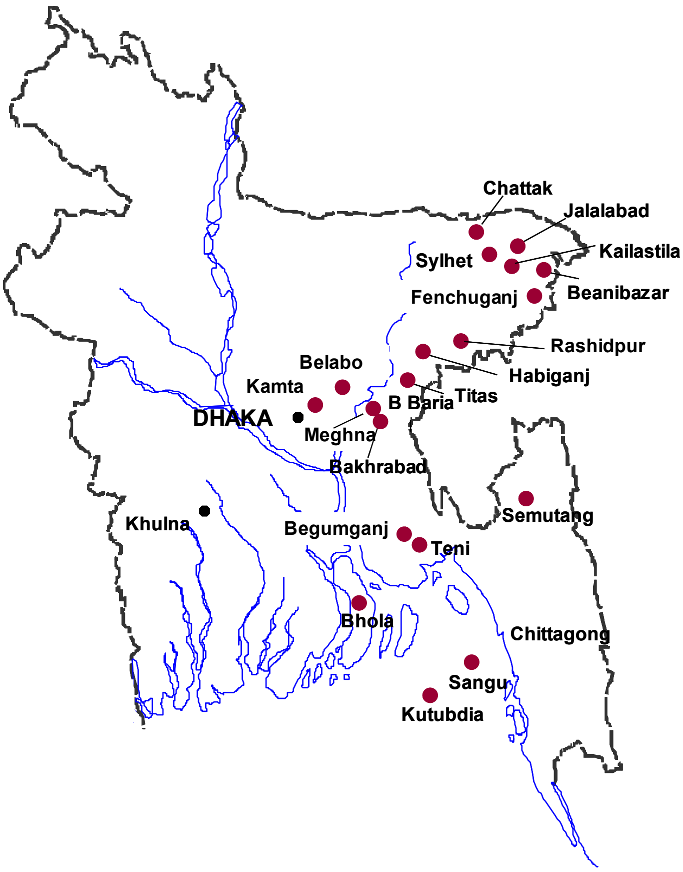


Figure 3-1 Principal Gas Fields in Bangladesh

*30% of the gas production is generated by independent producers.*

The other key producing fields are the Khalastila field and the Jalalabad field, which came onstream in early 1999, both of which are operated by Unocal. The offshore Sangu field is operated by Cairn/Shell. The gas produced from these fields totalled almost **31%** of 2000 production. The gas produced by these independent companies is transported and marketed by Petrobangla to domestic consumers.

Production from the Sangu field, the first to be foreign-operated, began in 1998 and is one of Bangladesh's most important discoveries to date.

Table 3-1 Gas Production in Bangladesh since 1991 in bcm per year

| Year | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Titas** | 2.3 | 2.6 | 2.8 | 2.7 | 2.7 | 2.8 | 2.8 | 3.0 | 2.9 | 2.9 | 3.6 | 3.6 | 34.7 |
| **Habiganj** | 0.8 | 0.8 | 1.3 | 1.4 | 1.5 | 0.2 | 1.6 | 1.7 | 1.8 | 1.8 | 2.0 | 2.4 | 17.3 |
| **Bakhrabad** | 1.4 | 1.5 | 1.4 | 1.3 | 1.4 | 1.5 | 1.1 | 0.9 | 0.5 | 0.4 | 0.4 | 0.4 | 12.2 |
| **Kamta** | 0.0 | 0.0 | - | - | - | - | - | - | - | - | - | - | 0.0 |
| **Feni** | - | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.0 | - | - | - | - | 1.1 |
| **Narsingdi** | - | - | - | - | - | 0.0 | 0.2 | 0.2 | 0.2 | 0.1 | 0.2 | 0.2 | 1.1 |
| **Meghna** | - | - | - | - | - | - | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.1 | 0.9 |
| **Salda** | - | - | - | - | - | - | 0.0 | 0.0 | 0.2 | 0.1 | 0.2 | 0.2 | 0.7 |
| **Sylhet** | 0.1 | 0.0 | 0.1 | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 1.0 |
| **Chhatak** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Kailashtila** | 0.2 | 0.2 | 0.2 | 0.3 | 0.3 | 0.5 | 0.6 | 0.9 | 0.9 | 0.9 | 0.9 | 0.8 | 6.7 |
| **Rashidpur** | - | - | - | 0.3 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.7 | 0.9 | 1.1 | 7.0 |
| **B'Bazar** | - | - | - | - | - | - | - | - | 0.0 | 0.1 | 0.0 | 0.1 | 0.2 |
| **Sangu** | - | - | - | - | - | - | - | 0.0 | 0.8 | 1.2 | 1.3 | 1.4 | 4.7 |
| **Jalalabad** | - | - | - | - | - | - | - | - | 0.3 | 0.8 | 0.9 | 0.9 | 2.9 |
| **Total** | **4.8** | **5.3** | **5.9** | **6.3** | **6.9** | **6.0** | **7.3** | **7.9** | **8.6** | **9.3** | **10.7** | **11.1** | **90.5** |

Source: Petrobangla

The Shahbazpur field was discovered in the Bhola area by Bapex in 1995 and is estimated to contain 330-400 bcf of recoverable reserves. In September 1998, Unocal and Petrobangla signed a PSC agreement to develop Shahbazpur. Unocal has proposed an integrated $250 million project, which would include a gas pipeline system to serve Western Bangladesh, gas fired power stations to be built at Bhola, Barisal and Khulna, and possibly supplies to other consumers. This would be central to a planned Western Region Integrated Project (WRIP) to bring development to the western half of Bangladesh.

### 3.4 Gas Transportation Infrastructure

The gas transportation system in Bangladesh links the fields in the north east of the country to Dhaka, the producing areas in the South East of the country and Chittagong.

***All transmission infrastructure is concentrated in the eastern part of Bangladesh.***

The present gas pipeline system in Bangladesh is the product of the original three regional systems which have been joined together by successive projects to form an integrated trunk line and distribution network. Currently all of the gas transmission infrastructure is in the eastern half of the country. However, there is a recently completed 30 inch pipeline connection across the Jamuna River bridge which is planned to be further extended on the western side of Bangladesh to bring gas to this part of the country.

A schematic diagram of the complete gas transmission and medium pressure distribution system is presented in the figure below:

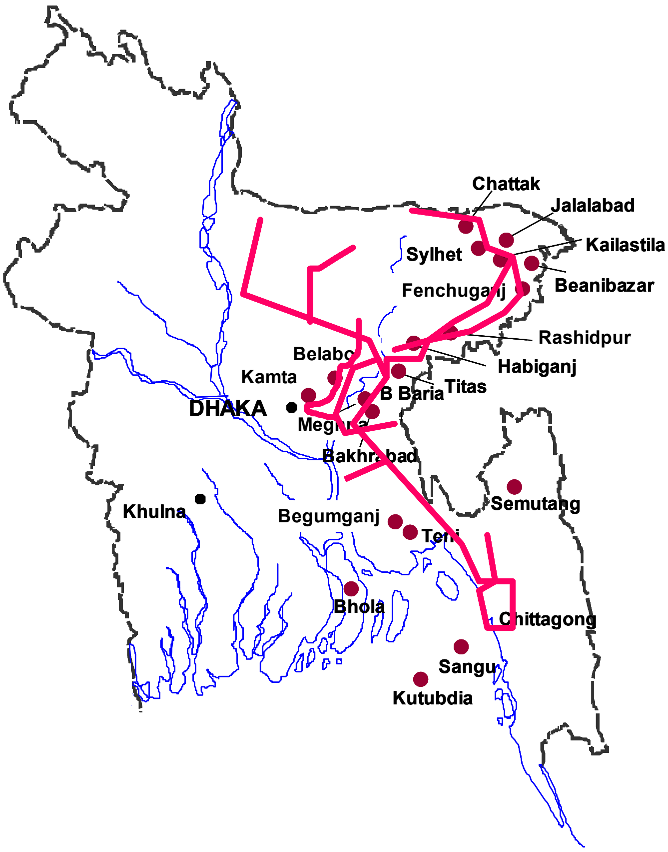


Figure 3-2 Major Gas Trunklines in Bangladesh

As with many other systems which have grown in this way, the piecemeal development has left several anomalies, both in the set up of the operating organization and in the sizing of many of the pipeline interconnections between previously separate pipeline networks. The transfer of the operation of the transmission network to a Petrobangla company, the Gas Transmission Company Limited (GTCL), leaves a system structure of national and international hydrocarbon production companies feeding the

GTCL transmission system, which in turn will supply gas to the three distribution companies, JGTDSL, TGTDCL and BGSL. This should result in a much improved gas supply situation because GTCL as an organization is able to focus on the efficient transmission of gas and the maintenance of the gas system, rather than concentrating, as the distribution companies do, on gas sales and expansion of the gas market.

There is no independent gas regulatory body within Bangladesh with a mandate to ensure safe pipeline transmission and distribution system operation.

### 3.4.1 System Operation

***There are bottlenecks and constraints in the transmission system and expansion of the system is needed.***

There are a number of bottlenecks in the existing system and expansion will be required to meet increasing future demand. The system is constrained at times of high demand, particularly to users in Dhaka, Chittagong and the major power stations. Whilst the current supply problems are primarily caused by insufficient gas production from the fields, the transmission and distribution system is causing bottlenecks in some places, again notably to users in Dhaka and within the supply lines from the northern area and Titas fields.

It is predicted that the current situation will rapidly deteriorate as the gas demand increases from new power stations and as new fields are brought onstream in the northern production area. As far as the pipeline network is concerned, the situation will to some extent be eased with new southern area fields such as Sangu reaching full capacity. This will have the dual effect of both reducing demand from the North and allowing the critical manifold at Ashuganj to be operated at a slightly lower pressure, thus giving the 24 inch north - south pipeline an increased capacity.

The transmission and distribution system is currently driven on field pressures with no intermediate compressor stations to boost the pressure. In order to counter falling supply pressures in the older fields, such as Bakhrabad, compressors to boost field pressures to pipeline operating pressures will need to be added at the fields if these fields are to be kept in production.

The transmission system currently has no provisions for pressure regulation between parallel pipelines. This, in several instances in the past, resulted in the reduced capacity of one or other of the parallel lines due to a high or low pressure constraint at one of its ends.

## 3.5 Gas Exploration

Bangladesh has been divided into 23 exploration blocks and offered for Production Sharing Contracts (PSCs). In the fall of 1997, Bangladesh held its second oil and gas licensing round. The key companies awarded blocks placing bids were Cairn and Royal-Dutch Shell on Block 5, and Unocal on Block 7. In February 1999, Cairn transferred operatorship of its natural gas blocks in Bangladesh to Shell. In December 1999, Unocal announced a major gas discovery at the Moulvibazar gas field in the Sylhet area, in Block 14.

The Irish oil and gas exploration and production company Tullow Oil PLC was awarded two exploration blocks (Block 9 and Block 11).

### 3.6 Gas Reserves

The official recoverable reserves figures for Bangladesh are 10.8 tcf or 307 bcm. Among recent finds, Unocal discovered a large natural gas reservoir within the Moulavi Bazar field (Block 14) in North Eastern Bangladesh. The Moulavi Bazar 2 well tested 0.85 million $m^3$/day of gas. Shell Bangladesh Exploration and Development also made another gas discovery, extending the Sangu field.

The published recoverable reserves figures are shown in the table below:

Table 3-2 Bangladesh Natural Gas Reserves Estimate in tcf - Petrobangla

| Field | | Proven Plus Probable Reserves | Recoverable Reserves | Remaining Recoverable Reserves |
|---|---|---|---|---|
| **Fields under production** | | | | |
| 1 | Sylhet (1955) | 0.444 | 0.266 | 0.097 |
| 2 | Rashidpur (1960) | 2.242 | 1.309 | 1.059 |
| 3 | Kailashtila (1962) | 3.657 | 2.529 | 2.255 |
| 4 | Titas (1962) | 4.138 | 2.100 | 0.124 |
| 5 | Habiganj(1963) | 3.669 | 1.895 | 0.953 |
| 6 | Bakhrabad (1969) | 1.432 | 0.867 | 0.262 |
| 7 | Jalalabad (1989) | 1.195 | 0.815 | 0.717 |
| 8 | Narshingdi (1990) | 0.194 | 0.126 | 0.088 |
| 9 | Meghna (1990) | 0.159 | 0.104 | 0.075 |
| 10 | Saldanadi (1996) | 0.200 | 0.140 | 0.117 |
| 11 | Sangu (1996) | 1.031 | 0.848 | 0.686 |
| 12 | Beanibazar (1981) | 0.243 | 0.167 | 0.156 |
| | **Total** | **18.604** | **11.166** | **6.591** |
| **Fields now suspended after production** | | | | |
| 13 | Chatak (1959) | 0.447 | 0.268 | 0.241 |
| 14 | Kamta (1982) | 0.033 | 0.023 | 0.002 |
| 15 | Feni (1981) | 0.178 | 0.125 | 0.086 |
| | **Total** | **0.658** | **0.416** | **0.329** |
| **Fields not yet developed for production** | | | | |
| 16 | Begumganj (1977) | 0.025 | 0.015 | 0.015 |
| 17 | Fenchugonj (1988) | 0.350 | 0.210 | 0.210 |
| 18 | Kutubdia (1977) | 0.780 | 0.468 | 0.468 |
| 19 | Semutang (1977) | 0.164 | 0.098 | 0.098 |
| 20 | Shahbazpur (1995) | 0.514 | 0.333 | 0.333 |
| 21 | Bibiyana (2000) | 3.150 | 2.401 | 2.401 |
| 22 | Moulvibazar (2000) | 0.500 | 0.400 | 0.400 |
| | **Total** | **5.483** | **3.925** | **3.925** |
| ***Total of all Fields*** | | **24.745** | **15.507** | **10.845** |

Source: Petrobangla 2002

***Bangladesh gas reserves are poorly exploited.***

Bangladesh remains a relatively poor exploited area. However, the geology indicates that the country may hold vast potential. Numerous studies have been conducted over the last few years but have been hampered by a lack of detailed exploration data and limited production history data on older Petrobangla-operated fields. Several estimates put the existing proven net recoverable reserves at 10–11 tcf but it is widely believed that the proven reserves could ultimately be in the range of 10-25 tcf, with some, notably international oil companies, indicating that the ultimate figure could be 40 tcf.

The table below shows recoverable reserves estimates from recent studies.

Table 3-3 Recoverable Reserves Estimates in tcf – from Recent Studies

| Source | Report | Date | Gas in place | Recoverable (probable + possible) tcf | Cumulative production tcf | Proven net recoverable reserves tcf |
|---|---|---|---|---|---|---|
| GoB and Petrobangla | National Energy Policy | Sept 95 | | 12.42 | | 10.44 |
| Petrobangla | | Mar 97 | 23.2 | 13.74 | | |
| Bechtel Consulting | 4th Natural Gas Plan (Asian Development Bank) | Aug 98 | 21.2 | 12.6 | 3.1 | 9.6 |
| US Geological Survey | Geological Assessment of the Fossil Energy Potential of Bangladesh | Dec 98 | | | | 20-25 tcf |
| Bangladesh Petroleum & Resource Assessment | MEMR Hydrocarbon Unit | Jan 2002 | | 28.4 | 4.3 | 20.4 |

A study undertaken by the MEMR Hydrocarbon Unit in Jan 2002 indicates that the total reserve base may be substantially higher than earlier estimates

Table 3-4 Discovered Reserves Estimates in tcf – from Recent Studies – MEMR Hydrocarbon Unit Jan 2002

| | | Proved | Proved + Probable | Proved + Probable + Possible |
|---|---|---|---|---|
| Discovered Reserves | Produced to June 2000 | 4.3 | 4.3 | 4.3 |
| | Remaining in fields | 10.9 | 11.6 | 16.2 |
| | Not in production | 2.1 | 4.5 | 7.9 |
| | Remaining reserves | 13.0 | 16.1 | 24.1 |
| | **Total Discovered** | **17.3** | **20.4** | **28.4** |

Table 3-5 Undiscovered Reserves Estimates in tcf – from Recent Studies – MEMR Hydrocarbon Unit Jan 2002

| | | $P_{90}$ | Mean | $P_{10}$ |
|---|---|---|---|---|
| Undiscovered Resource | Hypothetical (Mapped projects) | 10.6 | 16.9 | 24.0 |
| | Speculative (Leads / Unmapped projects) | 7.8 | 24.7 | 39.7 |
| | **Total Undiscovered** | **18.5** | **41.6** | **63.7** |

This study indicates 28.4 tcf in the proven + probable + possible category, i.e greater than **50%** probability and also up to 63.7 tcf of undiscovered gas reserves at greater than **10%** probability level. This gives a total reserves range of anywhere between 47 tcf and 92 tcf.

The issue of existing gas reserves is a highly contentious issue in Bangladesh. The country is far from fully explored and it is very likely that new fields will be discovered. In a gas province such as Bangladesh where there has been limited exploration activity, it is anticipated that more significant finds will be made.

***More data is needed to prove up further reserves in Bangladesh.***

The existing proven and probable estimates are based upon existing exploration and production data compiled by Petrobangla and, more recently, international companies. The data from most existing fields is limited. The key to proving up further reserves is to gather more exploration data using modern exploration techniques, such as 3D seismic, both on existing fields and prospective new areas.

Petrobangla does not have the resources to undertake this work. The international companies do but are reluctant to invest more money in exploration when there is no certainty that they will be able to market any gas they find.

The existing Government of Bangladesh policy of ensuring that there are sufficient supplies reserved for domestic consumption and the reluctance of

Petrobangla to take the gas output from international companies, due to the high price, has effectively put a brake on new exploration activity.

### 3.7 Projected Gas Supply

Potential future gas supply from Bangladesh will clearly depend upon a number of factors, not least the will of the Bangladesh government to contemplate gas exports.

***The future gas supply will depend on the speed of reserves development and pricing levels.***

The future gas supply situation for Bangladesh will be dependent upon a number of factors, including the speed of development, future pricing levels and the general consensus on reserves figures which may allow gas supplies for export.

The table below is based upon projections from Petrobangla and Bechtel Consulting's 4th Natural Gas Development Plan.

Table 3-6 Natural Gas Supply Projections for Bangladesh to 2011 (bcm)

| **Year** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** |
|---|---|---|---|---|---|---|---|---|---|
| **Developed Fields** | | | | | | | | | |
| Titas | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 |
| Habiganj | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 | 2.6 |
| Bakhrabad | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Kamta | - | - | - | - | - | - | - | - | - |
| Feni | - | - | - | - | - | - | - | - | - |
| Narsingdi | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Meghna | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Salda | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Sylhet | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Chhatak | - | - | - | - | - | - | - | - | - |
| Kailashtila | 0.9 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Rashidpur | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 |
| B'Bazar | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Sangu | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| Jalalabad | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| **Total** | **12.1** | **12.8** | **12.8** | **12.8** | **12.8** | **12.8** | **12.8** | **12.8** | **12.8** |
| **Undeveloped fields** | | | | | | | | | |
| Begumgonj | - | - | - | - | - | - | - | - | - |
| Fenchugonj | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 | 0.15 |
| Kutubdia | - | - | - | - | - | - | - | - | - |
| Semutang | - | - | - | - | - | - | - | - | - |
| Shahbazpur | - | - | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 | 0.4 |
| Bibiyana | 1.37 | 1.37 | 1.37 | 1.37 | 1.37 | 1.37 | 1.37 | 1.37 | 1.37 |
| Moulvibazar | - | - | - | - | - | - | - | - | - |
| **Total** | **1.52** | **1.52** | **1.92** | **1.92** | **1.92** | **1.92** | **1.92** | **1.92** | **1.92** |
| | | | | | | | | | |
| **Grand Total** | **13.61** | **14.27** | **14.67** | **14.67** | **14.67** | **14.67** | **14.67** | **14.67** | **14.67** |

The supply picture from developed fields will be stable at around 12.8 bcm (approx 1,260 MMSCFD). The picture from undeveloped fields is less certain but is projected to add an additional 1.9 bcm (190 MMSCFD) by 2005. Development of the Kutubdia field and further development of Bibiyana could potentially add up to 3 bcm per year (295 MMSCFD) to the gas supply picture. Obviously the discovery of more gas fields could significantly change the supply outlook from undeveloped fields.

## 3.8 Gas Pricing

### 3.8.1 Gas Produced by Petrobangla

***Gas price fixed on an ad-hoc basis by the Government.***

Gas prices in Bangladesh are fixed on an ad-hoc basis by the Government. The different agencies involved in the formulation of the gas pricing policy are: the Ministry of Finance; the National Board of Revenue; the Ministry of Energy and Mineral Resources and Petrobangla.

The government-administered prices are composed of 4 elements:

- Excise duty
- Production Margin
- Transmission and Distribution Margin
- Contribution to BAPEX

The transmission and distribution margins are uniform over the whole system for each category of customer, which are grouped as:

- Power
- Fertiliser
- Industrial
- Commercial
- Residential
- Tea Estates.

The delivered cost of gas to different consumer categories is shown in the table below:

Table 3-7 Gas Pricing to End Users in Bangladesh by Sector per MCF

| | | Power | | Fertilizer | | Industrial | | Commercial | |
|---|---|---|---|---|---|---|---|---|---|
| As of | Exchange Rate | Tk | US$ | Tk | US$ | Tk | US$ | Tk | US$ |
| 01/01/1995 | 40.10 | 47.57 | 1.19 | 41.34 | 1.03 | 103.07 | 2.57 | 147.53 | 3.68 |
| 01/01/1996 | 41.75 | 47.57 | 1.14 | 41.34 | 0.99 | 103.07 | 2.47 | 147.53 | 3.53 |
| 01/01/1997 | 43.65 | 47.57 | 1.09 | 41.34 | 0.95 | 103.07 | 2.36 | 147.53 | 3.38 |
| 01/01/1998 | 46.30 | 47.57 | 1.03 | 41.34 | 0.89 | 103.07 | 2.23 | 147.53 | 3.19 |
| 01/01/1999 | 48.50 | 54.71 | 1.13 | 47.54 | 0.98 | 118.53 | 2.44 | 169.66 | 3.50 |
| 01/01/2000 | 51.00 | 54.71 | 1.07 | 47.54 | 0.93 | 118.53 | 2.32 | 169.66 | 3.33 |
| 01/01/2001 | 55.00 | 62.86 | 1.14 | 54.65 | 0.99 | 136.77 | 2.49 | 195.39 | 3.55 |

Source: Petrobangla 2001

***Gas pricing in Bangladesh is low by international standards.***

Gas pricing in Bangladesh is low by international standards, reflecting in part relatively low production costs, but more particularly, direct subsidies to consuming sectors through gas prices. It is estimated that electricity consumers, fertiliser plants and households receive around $600 million per year in direct subsidies and savings associated with their gas consumption.

***Consumers are subsidised by approximately $600 million per year.***

The margins allowed to the distribution companies are not sufficient for them to undertake long-term capital investments and are not based upon the real costs of meeting demand. There is no transfer pricing structure between the transmission and the distribution companies.

***A new pricing structure taking into consideration peak and off-peak demand should be implemented to encourage energy conservation and sector development.***

About two-thirds of the country's load of natural gas has a pronounced difference between peak and off-peak demand. Such variations impose a significant cost on the supply system, as production facilities and the pipeline network need to be sized and equipped to supply gas at peak loads. The existing pricing system does not reflect these costs and gas shortages are experienced during the peak hours between 1800 hrs and 2200 hrs. Consideration should therefore be given to introducing peak and off-peak tariffs, particularly for power generation, fertilisers and industry. These gas prices will provide the right signals to the power sector, internally encouraging the introduction of peak and off-peak tariffs and promoting energy conservation. The two-part gas tariffs would involve a fixed monthly capacity charge, covering capacity costs and customer related expenses, and a volume charge reflecting annual consumption.

### 3.8.2 Gas Produced under PSC

The pricing system for international companies producing gas under PSC contracts is as follows:

- The pricing for associated gas is on a cost plus basis (although it is not clear how costs would be divided and attributed between gas and liquid streams).
- For non-associated gas the price of gas is **75%** of the international price of heavy fuel oil (basket at Singapore), and to encourage exploration in offshore areas the gas from these fields is priced **25%** higher than from onshore fields. This gas is sold exclusively to Petrobangla which then distributes the gas.

***The gas produced by international companies is more expensive than the Petrobangla prices.***

The linking of the PSC produced gas to fuel oil prices posted in Singapore has effectively made the gas produced by the international companies more expensive than the gas produced by Petrobangla and generally higher than the price than Petrobangla is selling gas to its customers. This has led to reluctance from Petrobangla to purchase gas from the international companies and maximise production from its own fields.

## 3.9 Gas Demand

Natural gas currently provides about **70%** of the country’s commercial energy requirements, against less than **40%** in the early 1980s. Since the early 1980s gas demand has reflected and driven the country’s development. Over the past two decades the consumption of gas has increased over 8 fold. In 1980/81 gas demand was 1.1 bcm (41 bcf), rising in 1993/94 to 5.8 bcm (210 bcf) and in 2000/01 to 10 bcm (353 bcf).

Table 3-8 Gas Consumption for Bangladesh for 2000

| **Industry** | **Consumption (bcm)** | **Proportion of the total (%)** |
|---|---|---|
| Power generation | 4.42 | **44%** |
| Fertiliser industry | 3.14 | **31%** |
| Industry | 1.19 | **12%** |
| Domestic & Commercial | 1.25 | **13%** |
| **Grand Total** | **10.00** | **100%** |

Sourc:e Cedigaz 2000

The principal demand for natural gas in Bangladesh comes from power generation and fertiliser production. Gas is used to feed power plants with a total nominal capacity of 2 GW and fertiliser plants with a total capacity of 2.5 million tonnes. Some **44%** of the gas delivered is used in power generation, with **31%** used in the production of fertiliser. Industry accounts for almost **12%** of natural gas consumption.

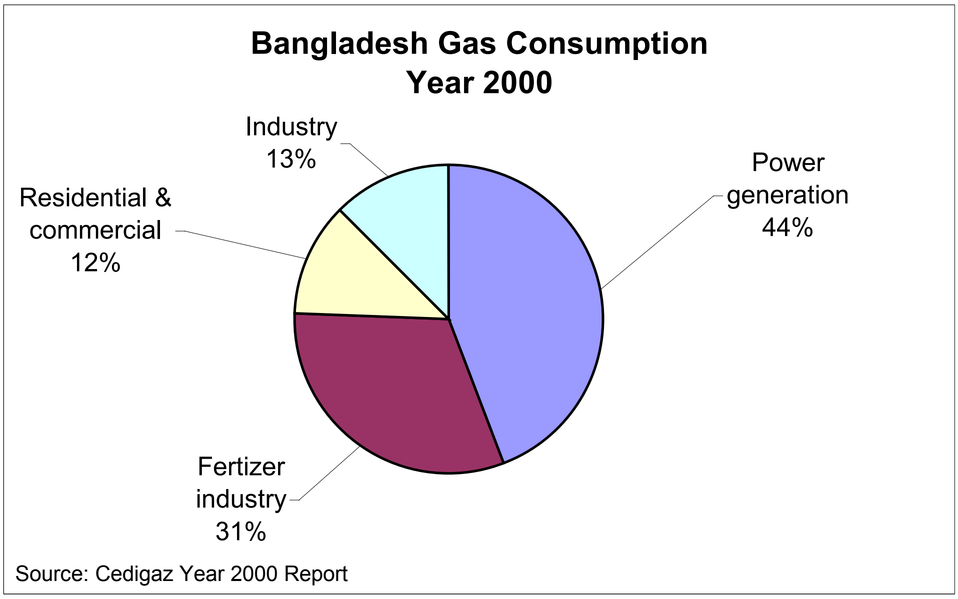


Figure 3.3 Breakdown of Gas Consumption in Bangladesh 2000

Increasing gas use in power generation is fuelling a number of large projects, e.g. the government-authorised Unocal development of the West Region Integrated Project (WRIP). Unocal signed a production-sharing agreement with their partner Bangladesh Petroleum Exploration Company (Bapex), to produce gas from the Shahbazpur field (Block 7). This gas will supply a 350 MW power plant.

### 3.10 Projected Future Gas Demand

Gas demand has risen substantially over the last two decades, growing at up to **10%** per annum, albeit from a very low base. Demand is forecast to rise significantly over the next decade with annual grow rates of around **6%** expected.

***Future consumption in Bangladesh will continue to be dominated by the power sector and the fertiliser industry.***

Existing and future consumption of natural gas in Bangladesh will continue to be dominated by two main users, the power sector and the fertiliser industry. Most of the natural gas demand growth is expected to be driven by the power sector where new independent power producer (IPP) schemes are planned to play an increasingly important role in the generation of electricity in Bangladesh.

Power generation and supply has been a long-standing problem in Bangladesh, due to a cycle of subsidised tariffs, chronic non-payment and theft, resulting in inadequate funding for operation, maintenance and future investment. Plans to provide new power generating plant in Bangladesh have been crippled by a lack of finance and long overruns on construction programs. In 1996, the government launched a program to encourage private investment in power through IPPs, although to date investment in this area has been slow.

In the fertiliser sector there is likely to be little growth as production of fertiliser from new plants is doubtful economically. Furthermore, analysts in Bangladesh indicate that if there is a need for increased fertiliser production capacity, efforts should be directed at rehabilitating existing plants and/or phasing out old plants and replacing them with new units constructed on the same sites. According to the guidelines of the Government of Bangladesh's National Energy Policy promulgated in 1995, "it is recommended to limit the total production of natural gas-based fertilisers to domestic demand". Obviously, this reflects the fact that the price of gas supplied to the state-owned fertiliser plants is heavily subsidized.

***The introduction of natural gas supply into the western region will depend on base-load schemes.***

A cornerstone of future gas demand is the development of the Western region of Bangladesh, where potential demand for natural gas is presently limited to projected supplies to existing and planned power units. This very low-income zone has an extremely low level of electricity connection, and the main contribution of gas to the region will be the increase of the electrification rate and the provision of an affordable and reliable source of electricity supply. The introduction of natural gas supplies into the western region will need to be economically justified by base-load schemes such as gas-fired power projects. These projects would serve as anchor users for further gas market development in the areas where they are sited.

The medium term forecast for demand from Petrobangla is shown in the table below:

Table 3-9 Gas Demand Forecast by Sector, Bangladesh (2003-2010) in bcm

| Year | Power | Fertiliser | Industry | Domestic + Commercial | Total |
|---|---|---|---|---|---|
| 2003 | 5.84 | 2.4 | 1.87 | 1.34 | **11.45** |
| 2004 | 6.17 | 2.6 | 2.01 | 1.4 | **12.18** |
| 2005 | 6.62 | 2.6 | 2.18 | 1.45 | **12.85** |
| 2006 | 7.04 | 2.96 | 2.35 | 1.51 | **13.85** |
| 2007 | 7.65 | 2.96 | 2.35 | 1.51 | **14.47** |
| 2008 | 8.44 | 2.96 | 2.88 | 1.7 | **15.98** |
| 2009 | 9.05 | 2.96 | 2.88 | 1.7 | **16.59** |
| 2010 | 9.69 | 2.96 | 3.13 | 1.79 | **17.57** |
| **Total (2003-2010)** | **60.5** | **22.4** | **19.65** | **12.4** | **114.94** |

Source : Petrobangla 2001

In the period of 2010 gas demand is expected to increase significantly, with the bulk of the growth in the power sector.

***Gas pricing below international levels distorts demand.***

The interrelationship of demand forecasts and pricing is problematic as the demand forecasts do not consider the demand for gas at international prices (such as those received by the international oil company producers). The existing demand forecasts for gas could be considerably constrained as prices move towards international structures. This is particularly true in the fertiliser sector, where if international gas pricing were to be implemented much of the production in Bangladesh would be uncompetitive, i.e. it would be cheaper to import fertiliser from the Arabian Gulf.

It is clear that the main demand driver will be the development of new gas-fired power plant, the requirement for which is substantial. However, there is some doubt as to how much of this capacity will actually be constructed in the planning horizon.

The long-term forecasts from Petrobangla are shown in the table below:

Table 3-10 Long Term Gas Demand Forecast by Sector, Bangladesh in bcm (2001-2050)

| Sector | 2001-2010 | 2011-2020 | 2021-2030 | 2031-2040 | 2041-2050 | Total |
|---|---|---|---|---|---|---|
| Power | 70 | 147 | 231 | 308 | 355 | **1,111** |
| Fertiliser | 27 | 31 | 25 | 25 | 25 | **133** |
| Industrial | 23 | 47 | 80 | 106 | 122 | **378** |
| Dom/Comm/Others | 15 | 22 | 29 | 34 | 37 | **138** |
| Total | **135** | **248** | **365** | **473** | **540** | **1,760** |

Source : Petrobangla 2001

The long-term gas demand figures show consumption in the power sector doubling in each of the next two decades and then doubling again over the following two decades. This implies that over 25,000 MW would be running on natural gas by 2040, compared to a total power generating installed capacity of 3,300 MW today, of which gas fuelled plant makes up about 2,000 MW.

### 3.11 Gas Supply/Demand Balance

***The future gas supply/demand balance will depend upon the development of the gas sector.***

The future supply/demand balance for gas will essentially depend upon the ability of Bangladesh to mobilise the resources required to develop the gas sector, be they from the public or private sector.

The natural gas supply/demand balance, using the projected Petrobangla gas demand and the supply scenario shown in Table 3.5, is shown in the table below:

Table 3-11 Bangladesh Supply/Demand Balance until 2011(bcm)

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| **Gas Supply** | 13.61 | 14.27 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 | 14.67 |
| **Gas Demand** | 11.45 | 12.18 | 12.85 | 13.85 | 14.47 | 15.98 | 16.59 | 17.57 | 18.56 |
| **Balance** | 2.16 | 2.09 | 1.82 | 0.82 | 0.20 | -1.31 | -1.92 | -2.90 | -3.89 |

Using the Petrobangla demand projections, the overall supply balance is in surplus until 2007 and in deficit thereafter. The keys to this are the demand projections, which could be considered very optimistic, almost doubling over the period to 18.56 bcm by 2011.

In 1996 the Government of Bangladesh adopted a National Energy Policy (NEP) that recommended production be limited to 1,000 MSCFD (approx. 10 bcm/year) unless there were significant additions to proven current reserves.

For the purpose of the above demand forecast, Petrobangla has taken 11.61 Tcf as remaining recoverable reserves, and it was assumed that there would be no production or infrastructure constraint in future from both supplier and consumer points of view. This would therefore mean that supply will always follow demand. However, the current remaining recoverable reserves will be exhausted by 2019 and thereafter production will fall short of demand.

Foreign energy companies believe, however, that these reserves might actually be much higher, possibly making Bangladesh a major gas producer (as well as supplier to the vast potential market in neighbouring India) at some point. Bangladesh could also use its gas resources to power vehicles (the government already has announced plans to convert government vehicles to compressed natural gas to help alleviate pollution problems in Dhaka), and to produce electricity, petrochemicals, and fertilisers, which could be used both within the country as well as for export. Gas exports are controversial within Bangladesh, with many people feeling that Bangladeshi gas resources should primarily be used for domestic purposes (i.e., electric power generation, development of related industries), while the size of the country's gas reserves remains highly uncertain, particularly in relation to future demand projections.

### 3.12 Summary

***Gas exports are controversial, priority is given to domestic requirements.***

Assuming that the projected demand is not depressed by future pricing policies and that transportation infrastructure constraints do result in supply restrictions, Bangladesh has sufficient natural gas for at least 20 years and very probably considerably longer. If recoverable reserves forecasts of 40 tcf prove to be true then Bangladesh would be able to meet project even aggressive demand forecasts for at least 40 years.

To date, a policy of ensuring that Bangladesh has enough reserves to cover 50 years of domestic demand is in place. This policy has frustrated export plans for the supply of gas by pipeline to India, drafted by the international companies who are seeking to maximise production from the investments they have made in developing the fields in Bangladesh.

### 4.1 Introduction

Oil and gas were first discovered in India in 1886 with a non-commercial oil well in Upper Assam. In 1889, the Assam Railway & Trading Co. struck oil at Digboi, Upper Assam. Later, this area was acquired by Burmah Oil Co. The Naharkatyia oilfield in Assam was the first oil and gas discovery of independent India in 1953, followed by the discovery of the Moran field in 1956.

India's first serious push in oil and gas exploration came in the late 1950s. In the years that followed, production ramped up as result of significant discoveries in the western offshore and Assam regions. Oil and gas were discovered in the onshore Cambay basin, Gujarat in 1958. Exploration of the western offshore basin area off Bombay began in 1964 and in 1974 the massive Bombay High field was discovered. The giant South Bassien free gas field was discovered in 1978.

The early discoveries focused on oil production and as consequence large amounts of associated gas from producing oil fields were flared because of a lack of infrastructure and developed markets. Free gas field finds were shut in for lack of offtake infrastructure, e.g. Bassien. The growth of gas production in India is shown in the figure below:

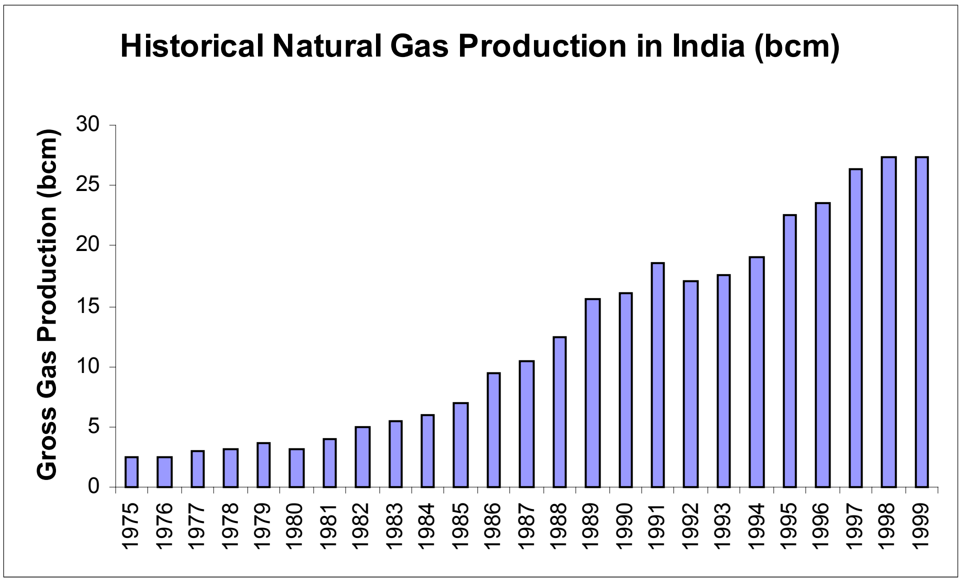


Figure 4-1 Gas Production in India from 1970

In the early 1980's, the western offshore gas began to be exploited as a resource rather than treated as a by-product and plans were set in motion to exploit gas for fertiliser manufacture and power generation. In 1986, work began on the HBJ gas transmission line linking the western offshore gas fields with fertiliser and power consumers between Hazira, Bijaypur and Jagdishpur. This allowed the utilisation of western offshore gas production, resulting in significant growth in gas production throughout the late 1980's. Flaring from the western offshore has diminished substantially in recent years and is now limited to technical flaring.

Associated gas production in Assam has remained steady over the last 20 years, although flaring has remained at high levels. There have been low levels of gas production in Arunachal Pradesh. Other fields in Rajasthan, Tamil Nadu and Andhra Pradesh have been exploited during the 1990's. Currently, most of India's gas is produced from the western offshore fields.

## 4.2 Gas Sector Organisation

***90% of India's gas is produced by state-owned companies and GAIL has a monopoly on the sale and transport of natural gas.***

At present, the gas sector in India consists of wholly state-owned companies: Oil & Natural Gas Co. (ONGC) and Oil India (OIL), which produced over **87%** of India's gas in 1999/00, and the Gas Authority of India (GAIL) which has a practical monopoly on the sale and transport of natural gas.

The Ministry of Petroleum and Natural Gas (MoPNG) oversees the whole chain of the oil and gas industry: exploration and production, refining, distribution, and the marketing of oil and gas products. It also oversees imports and exports of crude oil and oil products. Several organisations come under the purview of the MoPNG:

- Directorate General of Hydrocarbons – set up in 1993 with the objectives of ensuring correct reservoir management practices, monitoring exploratory programmes, managing production, and developing plans for national and private oil companies;
- Oil Coordination Committee – this organisation undertakes responsibilities in planning, coordinating, advisory and regulatory issues related to the downstream sector;
- Oil and Natural Gas Corporation (ONGC) –this is the dominant exploration and production company in India, accounting for over **90%** of production. Its subsidiary, ONGC Videsh Limited, undertakes exploration and production activities overseas;
- Oil India Limited (OIL) – undertakes exploration and production activities in India.
- Gas Authority of India (GAIL) - Gas transmission comes under the authority of the GAIL, which was established in 1984. GAIL was formed to oversee and develop the use of natural gas in India and to operate gas transmission systems already in existence and the HBJ line, commissioned in 1987/88. The transmission of gas in Assam is undertaken by the Assam Gas company, a state government undertaking, which supplies the majority of gas produced by OIL in Assam to various consumers.

There are several joint venture companies active in the gas sector in India:

- Mahanagar Gas Limited (MGL) - A joint venture with British Gas and the Government of Maharashtra was incorporated to supply gas to domestic, commercial and small industrial consumers in Mumbai, and

CNG for the transport sector. Over 15,000 vehicles are running on CNG.

- Indraprastha Gas Limited (IGL) - A joint venture company with BPCL and the Government of Delhi was incorporated in 1998 for the distribution of natural gas to the domestic, commercial and transport sector in Delhi. Over 1,500 houses in Delhi, not including some commercial users, are being supplied piped gas, and more than 3,000 cars are running on CNG.

- Petronet LNG Limited (PLL) - A joint venture with ONGC, BPCL and IOC was incorporated for the import of LNG in the country. Petronet LNG's mandate is twofold – to identify locations in India where it can set up LNG terminals while simultaneously organising LNG supply, and secondly to bid for individual tenders released by Indian state governments.

***To meet the growing gas deficit, India has taken initiatives to encourage private sector investment into the E&P sector.***

Although the state-owned enterprises increased hydrocarbon production and reserves base significantly over the period 1975 to 1990, the gap between domestic production and demand widened significantly in latter years. As a result, initiatives were taken to encourage private sector investment into the E&P sector, with exploration acreage offered to private companies under production sharing arrangements with the Indian government.

In 1994 the government awarded the first joint venture (JV) fields. Joint ventures and private companies currently operate 18 fields, most of which are small. The state-owned companies are shareholders in JV's for medium sized fields, although there is no participation in small sized fields. Since 1984, one free gas field in this region, Tapti, and the Panna/Mukta associated gasfield have been operated under joint ventures by the now-defunct US company Enron. British Gas is currently in discussions to take over these fields. Command Petroleum operates the Ravva field in a joint venture with ONGC in the Krishna-Godavari basin.

There is no foreign participation in the downstream gas sector.

### 4.3 Gas Production

Natural gas production and development in India has undergone major growth in the last 30 years, growing from a production rate of 1.4 bcm in 1975 to 28.5 bcm in 1999/00. There are five major areas of gas production in India, shown in the figure below.

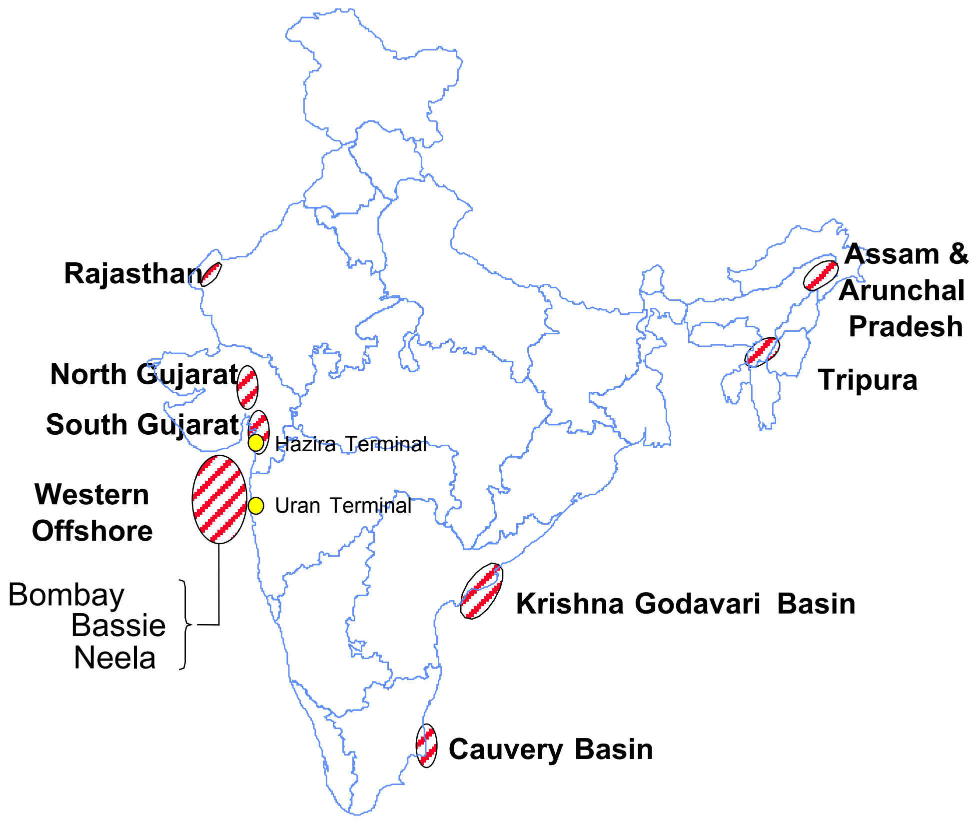


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Figure 4-2 – Principal Gas Production Regions of India

The major gas producing regions are:

- The Western Offshore region, which extends from offshore Bombay to Gujarat;
- North Gujarat, with two production areas;
- The Krishna Godavari basin on the central east coast;
- The Cauvery basin on the south central east coasts;
- Assam and Arunachal Pradesh in the north east.

There are also gas fields in Rajasthan and Tripura

At the present time it has been estimated that only some **27%** of the sedimentary area has been explored, although the explored area includes all the areas that are presently considered to be geologically most prospective. The current output is heavily concentrated on the western offshore fields, which produced 17.7 bcm of the total 28.5 bcm of gas production in 1999/00

Production targets are set by the MoPNG in five-year plans. Under the ninth five-year plan, the gas production reached 27.4 bcm in 1998/99 and 28.3bcm in 1999/00. The reserves-to-production (R/P) ratio is relatively low, about 31 years compared with the world average of about 61 years.

The gross production figures up to year 1999/2000 are presented below.

Table 4-1 Gross Production of Natural Gas 1991 to 1999/2000 (bcm)

| | 91/92 | 92/93 | 93/94 | 94/95 | 95/96 | 96/97 | 97/98 | 98/99 | 99/00 |
|---|---|---|---|---|---|---|---|---|---|
| ***Onshore*** | | | | | | | | | |
| Gujarat | 1.70 | 1.95 | 2.17 | 2.46 | 2.88 | 2.93 | 3.12 | 3.17 | 3.10 |
| Assam/ Nagaland | 0.03 | 0.05 | 0.05 | 1.91 | 1.88 | 1.94 | 2.02 | 2.06 | 2.08 |
| Arunachal Pradesh | 0.27 | 0.67 | 0.78 | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | 0.02 |
| Tripura | - | - | - | 0.09 | 0.13 | 0.15 | 0.19 | 0.30 | 0.35 |
| Tamil Nadu | - | - | - | 0.10 | 0.12 | 0.09 | 0.10 | 0.11 | 0.14 |
| Andhra Pradesh | - | - | - | 0.64 | 0.68 | 0.80 | 1.02 | 1.22 | 1.36 |
| Rajasthan | - | - | - | - | 0.01 | 0.01 | 0.15 | 0.16 | 0.15 |
| **Total** | **4.25** | **4.71** | **4.98** | **5.24** | **5.73** | **5.95** | **6.62** | **7.04** | **7.21** |
| ***Offshore*** | | | | | | | | | |
| ONGC | 14.39 | 13.35 | 13.36 | 14.14 | 16.58 | 16.79 | 18.10 | 17.51 | 17.74 |
| Private/JV | - | - | - | - | 0.33 | 0.51 | 1.68 | 2.87 | 3.47 |
| **Total Gross Production** | **18.65** | **18.06** | **18.34** | **19.38** | **22.64** | **23.26** | **26.40** | **27.43** | **28.45** |

Source: TERI Yearbooks 1997/98 and 2001/02

***The current production is concentrated on the western offshore region, which produces 63% of the total gas production. Most of the infrastructure is concentrated in the west and north west of India.***

The current output is concentrated on the western offshore fields, which produced 17.74 bcm of the total 28.45 bcm of gas produced in 1999/00, amounting to **63%**. Onshore Gujarat fields were the other major producing areas with 3.10 bcm in 1999/00. The other producing areas Assam, Tripura, Cauvery Basin and Krishna-Godavari contributed 3.9 bcm in 1999/00.

## 4.4 Gas Transportation Infrastructure

Currently in India, infrastructure exists for the production and transportation of about 90 MMcm/day of gas and the transmission and distribution of about 65-70 MMcm/day. Most of the infrastructure is installed in the west and north west of India for the transportation of gas to shore from the western offshore fields, and the transmission of this gas to end users. By far the largest of the transmission systems is the HBJ line, which takes gas from Hazira to Delhi, Gujarat, Madhya Pradesh, Uttar Pradesh and Rajasthan.

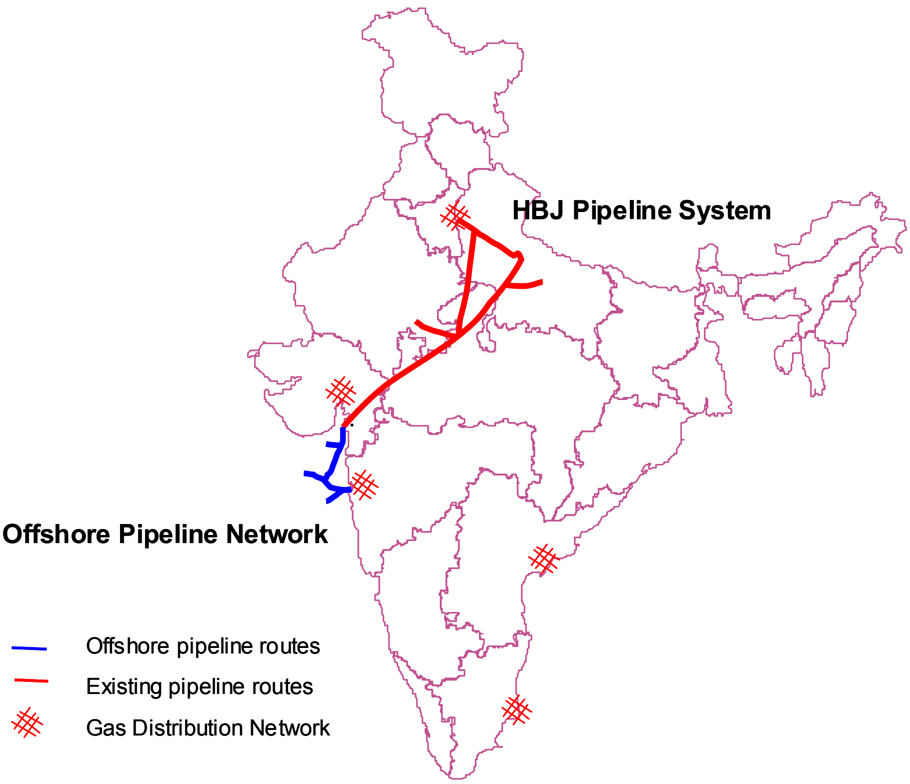



Figure 4-3 Gas Infrastructure in India

The major gas infrastructure networks are shown in the figure above.

### 4.4.1 Offshore Supply Infrastructure

There is around 3,700 km of gas pipeline laid offshore in India, of which almost 1,000 km is gas trunkline network. The western offshore region contains most of India's production infrastructure with the fields supplying the Uran and Hazira terminals in Gujarat. Associated gas from the Bombay High field is linked by a 26" gas line which connects to the Uran terminal. The Heera and Neelam fields are also connected to the Uran terminal by a 26" line. The Bassein field is linked to the Hazira terminal by a 36" and a 42" line. Also connecting to these lines is a 18" transmission line bringing gas from the Tapti fields and another line that feeds gas from the Panna-Mukta fields.

The Bombay High (BHN-Platform) Uran pipeline has a capacity of around 4.5 bcm/y of gas. The Heera-Uran pipeline has a design capacity of 5.8 bcm/y. The two gas pipelines from South Bassein to Hazira have capacities of 8 bcm/y and 11 bcm/y respectively

### 4.4.2 Onshore Infrastructure

The terminal at Uran can handle 5.8 bcm/y of sweet gas with limited facilities to treat sour gas. The terminal at Hazira has been expanded to handle 15 bcm/y of sour gas. The Hazira Terminal has the gas sweetening facilities for treatment of sour gas from South Bassein and other offshore fields.

In total, there is around 3,900 km of gas transmission network installed in India, the longest and biggest of which is the HBJ trunk pipeline system which is more than 2000 km in length. There are regional gas grids of varying sizes in the states of Gujarat (Cambay basin), Andhra Pradesh (KG basin), Assam (Assam-Arakan basin), Maharashtra (Ex-Uran Terminal), Rajasthan (Jaisalmer basin), Tamil Nadu (Cauvery basin) and Tripura (Arakan basin).

Table 4-2 Summary of India's Onshore Pipeline System

| Pipeline System including spurs | Length (Km.) |
|---|---|
| HBJ | 2,552 |
| North Gujarat | 175 |
| South Gujarat | 460 |
| Ex-Uran Terminal (Maharashtra) | 1,07 |
| Krishna-Godavari Basin | 189 |
| Cauvery Basin | 66 |
| Assam | 174 |
| Tripura | 3 |
| Rajasthan | 65 |
| **TOTAL** | **3,791** |

Source: GAIL, MoPNG

The capacity of the HBJ system was expanded in 1997 with a 505 km pipeline and extra compression from Bijaipur (Vijaypur) and Dadri. The present grid spread is based on the gas availability from the regions as well as the outlook for future gas production.

***Further major pipeline activity would be needed if the pipeline gas import projects take shape.***

Clearly the need for further major pipeline activity would be triggered should pipeline gas import projects take shape. Utilisation of imported gas would require major trunk gas pipeline systems for the transportation of gas to various regional markets. The import of LNG would also lead to the requirement of new pipelines, but these would not be extensive for techno-economic reasons.

Considerable work is planned during the Ninth Gas Plan to set up domestic gas supply networks. Such a system is already being created in Bombay City by a joint venture between GAIL and British Gas, and its coverage will increase quite extensively during the next 4/5 years. Similar projects are being initiated for the industrial sectors in Delhi-Agra and Firozabad. The supply to Firozabad and Agra with gas is designed to promote substitution from polluting fuels being used by steel foundries and glass industries.

***Future investments in infrastructure will be needed if gas demands grow as projected …$10 billion required.***

For gas use to expand as anticipated, an adequate downstream infrastructure has to be built. GAIL estimates that investments required for the downstream sector are in the range of $10 billion.

Having planned four LNG receiving terminals in the state, representing a capacity exceeding 12 million t/year of LNG, the Gujarat Infrastructure development Board approved plans in late 1999 to lay a 1,500 km gas transmission grid.

### 4.4.3 LNG Import Terminals

Presently there are three LNG receiving terminals under construction, at Dabhol in Maharashtra, Dahej in Gujarat, and a third at development at Hazira, also in Gujarat. Currently there are plans for up to seven import terminals to be built in India, shown in the table below:

Table 4-3 Proposed LNG terminals for India

| Place | Start-up (Year) | Operator | Receiving Source | Comment |
|---|---|---|---|---|
| Dahbol. Maharashtra | 2003+ | Dahbol Power Company | Abu Dhabi, Oman | LNG import terminal under construction |
| Dahej, Gujarat | 2003+ | Petronet-LNG | Qatar | LNG import terminal under construction |
| Hazira, Gujarat | 2004+ | Shell India Terminal Company Ltd. (Essar, Gujarat Maritime Board) | To be decided | LNG import terminal under construction |
| Cochin, Kerala | 2004+ | Petronet-LNG | Qatar | LNG import terminal planned or proposed |
| Pipavav, Gujarat | 2004+ | BG, Skil, NTPC, Pipavav Port | - | LNG import terminal speculative |
| Ennore, Tamil Nadu | 2004+ | Tamil Nadu LNG & Power Co. | Qatar | LNG import terminal speculative |
| Jamnagar, Gujarat | 2004+ | Reliance | - | LNG import terminal speculative |
| Kakinada, Andhra Pradesh | 2005+ | - | - | LNG import terminal speculative |

LNG terminal projects have been proposed by large Indian industrial consumers, international oil companies, and consortia of local and international companies. Prominent in the development of LNG terminals has been Petronet LNG, a company set up in May 1997 as a joint venture between India's four principal oil and gas companies, GAIL, ONGC, OIL & BPCL. The company was given the status of a holding company and allocated start up capital of $3.2bn. On creation, Petronet LNG announced the formation of a steering committee with members from each group to co-ordinate relations with foreign gas suppliers and to examine bids. Contracts have been concluded between Petronet and RasGas for the supply of 7.5 MMTPA to terminals at Dahej and Cochin.

The Dabhol LNG terminal project, which is over **90%** complete, was developed by an affiliate of the Enron Corporation which collapsed in early 2002. There is now a question as to which company will take over this project.

The Ennore project in Tamil Nadu made early headway but progress has recently stalled due to insufficient power demand to back-stop an LNG project..

***Several LNG projects are expected to supply up to 17.1 bcm by 2010***

In Pipavav (Gujarat state), UK's BG International is considering a 2.7 million t/yr, $900 million LNG import facility to be expanded to 5.2 million t/yr.

Overall, LNG imports are expected to be in the range of 10.3 bcm to 17.1 bcm by 2010.

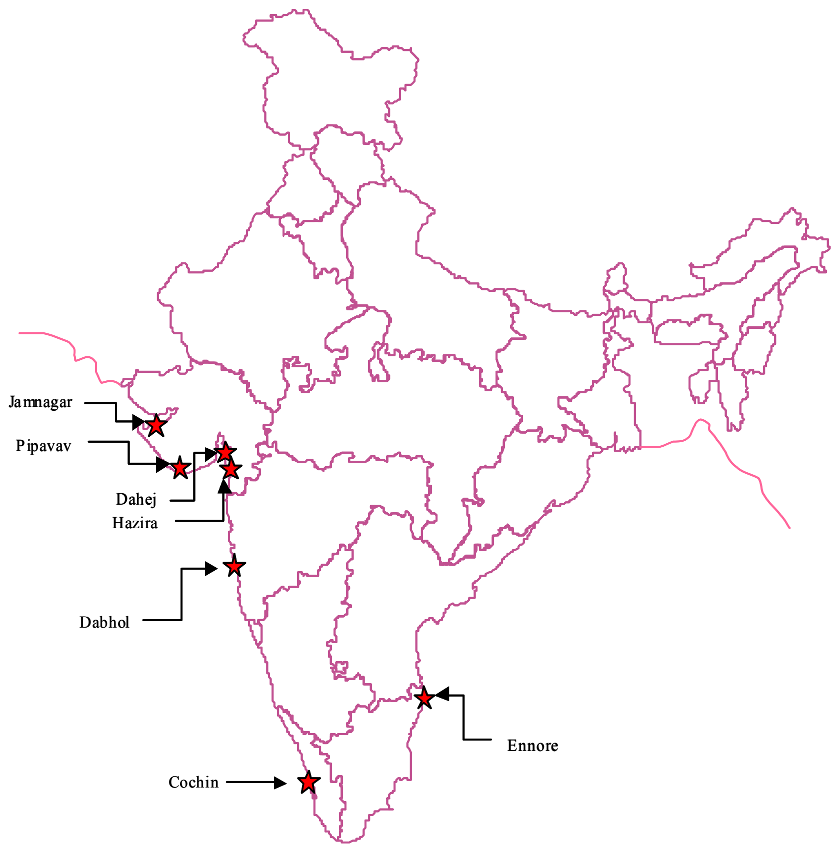



Figure 4-4 Location of Proposed LNG Terminals in India

## 4.5 Gas Exploration

Most of the major oil and gas finds in India came during a phase of heavy exploration the 1970's. During this period all the known major fields in India were identified, although in some cases development occurred much later. Exploration efforts have delineated the most prospective basins and, as illustrated in Table 4-5, there was a net addition to reserves until the 1990's. However, due to the lack of important finds in the last decade, gas reserves were dwindling until the very recent discoveries by Reliance in the Krishna-Godavari basin.

The three main producing basins in the country, the western offshore region, the Cambay basin in Gujarat, and Upper Assam region, are in the mature phase of exploration and, with the exception of Assam, future finds in these areas are not likely to be large in size.

***Potential for significant onshore discoveries in the east of India exists.***

In Assam and Nagaland, in the north eastern part of India, it is believed that the potential for significant onshore discoveries still exist. The major brake on developing this area has been the political instability of this region which has discouraged investment in capital projects.

Current estimates of the recently discovered fields in the Krishna Godavari basin place these new finds at around 7 tcf, although there is thought to be a significant likelihood of this figure increasing as the surrounding blocks are explored.

### 4.5.1 Exploration Activity

Although India's petroleum potential has been considered attractive, apart from Bombay Offshore, only two other large hydrocarbon regions have been identified: Assam and Gujarat. The density of exploratory drilling is relatively low compared, for example, with the proven hydrocarbon regions in Canada and the U.S. In the last decade India's exploration and production activity has been sluggish.

Prior to independence, private companies in India confined exploration efforts to the north east region. Although some private companies have been involved in the oil and gas sector since independence, exploration has been largely in the hands of ONGC and OIL, who had access to the best acreage. The largest build up of reserves came in the period 1985 to 1990, principally from the exploration efforts of ONGC, with additions to reserves dropping off by 1992.

Efforts were made in the mid 1990's to stimulate the exploration effort by deregulation of the energy sector, in particular the partial divestment of OIL and ONGC. So far, this divestment is yet to take hold, apart from a small allocation of shares to employees. At the same time, bidding for exploration acreage was opened to international competition.

The response by international companies to the exploration acreage offered to date has been weak, due to a combination of factors. The areas offered have not been considered attractive (with much of the prospective areas remaining in the hands of ONGC and OIL), all international partners are presently required to enter into joint ventures with OIL or ONGC, and the

***Limited interest in exploration from international companies.***

fiscal conditions on offer from the Government of India to producers have been set at relatively high levels which have discouraged new entrants, particularly into more high risk, high cost areas. The terms and conditions on offer have not been considered, as a whole, to be as attractive as elsewhere and international oil company E&P expenditure has been directed accordingly.

This, coupled with the bureaucratic delays in obtaining exploration licences, has discouraged most major oil companies from participating in the sector thus far.

### 4.5.2 New Exploration Licensing Policy

The 1996/7 New Exploration Licensing Policy (NELP) was designed to speed the process of gaining approval for licences, bringing India more closely in line with other oil producing nations in many of its features. Companies are now allowed to bid for blocks, producers are able to sell to customers at market prices, tax holidays are available on infrastructure expenditure and incentives for deep-water exploration have been introduced. These features have all increased the attractiveness of India to the international oil explorers.

It is understood that ONGC and OIL will have to bid for new acreage against other interested parties. It is uncertain whether ONGC and OIL will be required to relinquish any acreage currently under their control.

### 4.5.3 Upgrading of Reserves

One area of opportunity is in utilising the experience gained in other parts of the world, either by bringing in consultants or international operators to advise or even possibly take over operator-ship of existing producing fields. This is already happening in the Bombay High field, where consultants have been brought in to review the reservoir management and operations of the field, with a view to seeking ways to increase reserves/production.

A precedent has also been set with the Enron operatorship of the Tapti field, where reserves are reported to have been significantly increased from those announced under ONGC operatorship. (It should be noted that the increased reserves have yet to be substantiated by increased production.). While the example of the Tapti field does not necessarily imply that other fields could be upgraded, it is believed that expertise and technology developed and utilised in other regions could benefit India. It is common in the oil and gas industry for technology to be transferred through partnerships and alliances in this way.

### 4.5.4 New Discoveries

The potential for new discoveries in the western offshore/Cambay basin area is low. The area has been well explored since the 1970's and the prospect of a major find is widely believed to be small. Similarly the potential for large new finds in the Cauvery basin is also considered to be low.

The highest potential for sizeable new discoveries is thought to be in previously unexplored or under-explored areas, in particular offshore areas which have had less attention to date. While the west coast offshore region has some potential for new gas discoveries, attention has focused to the east coast due to the recent significant discoveries in the Krishna-Godavari basin.

The acreage on offer under the NELP reflects the greater potential of the offshore regions, with 28 blocks under offer offshore and 19 blocks onshore. The offshore blocks cover the direct offshore regions from the coast out to the continental shelf. These extend from south of Bombay on the west coast and incorporate most of the offshore coastline on the east coast. The onshore blocks are scattered, including tracts in the Himalayan foothills, the Ganga valley and central India.

- The North East - The Assam/Tripura region represents an area with immediate potential for gas prospect development. The development in Assam has been dictated by oil production and there have been few wells drilled to exploit gas. In Tripura, gas production has been slowed by a lack of gas markets. It is believed that with further exploration and development the production from the Tripura region could increase from the current potential of 2 MMcm/day, as there has been so far no drilling for deep structures.

- Krishna-Godavari Basin - Reliance has recently made discoveries estimated at around 7 Tcf in the region. The potential for further finds in the area is such that the figure could potentially rise as high as 15 Tcf according to the Directorate General of Hydrocarbons (DGH).

- Rajasthan - Developments in Rajasthan may yield new discoveries in the near future. However, past exploration efforts indicate that the size of field in this area is not likely to be very large and it is possible that there will be significant $CO_2$/Nitrogen levels.

- West Coast Offshore - The west coast offshore region holds reasonable promise of new large gas finds in the medium-term. This area includes the further deeper water reaches of the Western Offshore/Bombay High basin and the entire continental shelf from Bombay south, down the west coast of India. Speculative projections from ONGC have been made of potential reserves of up to 200 to 300 bcm in this region.

- Andaman - The Andaman region represents a long-term prospect in terms of exploitable resources. There are gas hydrates that have been identified at relatively shallow depths below the sea floor, around 800 metres. Below these hydrates it is believed that there are significant quantities of gas – indeed the only figure which has been publicly quoted is of a potential for 1,500 to 2,000 bcm in reserves.

  There are, however, significant technical issues to be resolved before such gas reserves could be exploited, notably the questionable accuracy of seismic interpretation of gas deposits below a hydrate cap and the difficulties in drilling through the hydrates with existing technology. The platforms would be located in 800 metres of water and require expensive deepwater technology. The fields are likely to be some 70 km from land.

The Andaman Islands are some 1,200 km from the Indian mainland, across the Bay of Bengal, the depth of which is over 3,000 metres. The transportation of any gas to India is likely to be high in cost, either by pipeline, if technically feasible, or by LNG. Any development of these resources is likely to come in the longer-term, 2015-2020.

## 4.6 Gas Reserves

### 4.6.1 Current Reserves

The proved natural gas reserves were estimated at 650 bcm as of 2000, according to the Cedigas 2000 Survey. Estimates based on figures from the Ministry of Petroleum and Natural Gas (MoPNG) indicate a figure of 648 bcm in 2000. An overview of the major fields in India and their size is presented in table below.

Table 4-4 Proven and Balance Recoverable Reserves of Natural Gas (bcm): 1991 to 2000

| Natural Gas Reserves (bcm) | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Onshore** | | | | | | | | | | |
| Gujarat | 93.4 | 94.0 | 92.9 | 92.1 | 94.0 | 91.1 | 89.1 | 88.7 | 84.4 | 82.5 |
| Assam | 151.7 ‡ | 160.5 ‡ | 156.1 ‡ | 156.2 ‡ | 125.6 | 131.4 | 133.8 | 137.9 | 142.2 | 148.5 |
| Rajasthan | 1.2 | 1.3 | 3.8 | 3.8 | 4.1 | 4.5 | 4.5 | 4.4 | - | - |
| ***Total Onshore*** | **246.3** | **255.7** | **252.8** | **252.1** | **223.7** | **227.0** | **227.4** | **231.0** | **226.6** | **231.0** |
| **Offshore** | | | | | | | | | | |
| Bombay High | 483.5 | 479.8 § | 465.1 § | 454.6 § | 414.7 § | 374.2 | 388.1 | 362.0 | 363.7 | 351.6 |
| **Total** | **729.8** | **735.6** | **717.9** | **706.7** | **676.1** | **641.3** | **692.1** | **674.8** | **648.0** | **647.5** |

‡ includes natural gas onshore reserves in Tripura, Nagaland, Tamil Nadu, Arunachal Pradesh and Andhra Pradesh

§ includes natural gas offshore reserves in Andrha Pradesh, Gujarat, Tamil Nadu, and Andaman and Nicobar islands

Source: TERI Yearbook 2001/2002

***The bulk of the proven reserves (>60%) are located on the western offshore region.***

Not including the recent Krishna-Godavari discoveries, the bulk of the proven reserves (>**60%**) are located on the western offshore region, the remainder mostly located in North East India (**24%**) and Gujarat (**13%**). Care should be taken when observing reserve ratios as a significant proportion of the reserves base is contained in gas caps which cannot be exploited until the oil field is depleted. Thus, while reserves to production ratio for 1995/6 is shown as 29:1, in fact the effective ratio was closer to 17:1.

### 4.6.2 Reserves Growth

The recoverable gas reserves base in India grew from 185 bcm in 1975 to 736 bcm in 1991, while 130 bcm was produced. After 1991 the reserves figure declined to 660 bcm by 1995. For the period from 1975 through to 1980 gas reserves were added at a much greater rate than gas was produced, the recoverable reserves in 1980 at 411bcm as against 185 bcm in 1975. The net addition to reserves continued through the mid 1980's at a lower rate and increased through to 1990, by which time recoverable reserves were at 730 bcm.

The period 1986 to 1990 saw significant proving-up of fields with net additions to the reserves, and this against production which increased almost two fold in the same period. From 1992 to 1994 there was a slow net depletion from the reserves figures, with the decline increasing in 1995.

Table 4-5 Reserve Replacement Ratio and Life of Reserves Natural Gas 1975 –1995/96

| Year | Recoverable reserves (bcm) | Net addition/ Depletion (bcm) | Production (bcm) | Gross addition to recoverable reserves (bcm) | Reserves replacement ratio* | Life of reserves (yrs current prodn.) |
|---|---|---|---|---|---|---|
| 1975 | 185 | 97 | 2.3 | 99.3 | 43.2 | 80.4 |
| 1976 | 339 | 43 | 2.4 | 45.4 | 18.9 | 95.0 |
| 1977 | 266 | 38 | 2.7 | 40.7 | 15.1 | 98.5 |
| 1978 | 344 | 78 | 2.8 | 80.8 | 28.9 | 122.9 |
| 1979 | 352 | 8 | 3.1 | 11.1 | 3.6 | 113.6 |
| 1980 | 411 | 59 | 2.1 | 61.1 | 29.1 | 195.7 |
| 1981 | 420 | 9 | 3.5 | 12.5 | 3.6 | 120.0 |
| 1982 | 475 | 55 | 4.7 | 59.7 | 12.7 | 101.1 |
| 1983 | 478 | 3 | 5.8 | 8.8 | 1.5 | 82.4 |
| 1984 | 479 | 1 | 6.6 | 7.8 | 1.2 | 70.4 |
| 1985 | 497 | 18 | 7.9 | 25.9 | 3.3 | 62.9 |
| 1986 | 541 | 44 | 9.5 | 53.5 | 5.6 | 57.0 |
| 1987 | 579 | 38 | 10.9 | 48.9 | 4.5 | 53.1 |
| 1988 | 648 | 69 | 12.8 | 81.8 | 6.4 | 50.6 |
| 1989 | 686 | 38 | 15.9 | 53.9 | 3.4 | 43.1 |
| 1990 | 730 | 46 | 18.0 | 64.6 | 3.5 | 39.3 |
| 1991 | 736 | 6 | 18.7 | 24.7 | 1.3 | 39.4 |
| 1992/3 | 718 | -18 | 18.1 | -1.0 | - | 39.7 |
| 1993/4 | 707 | -11 | 18.3 | 7.3 | 0.4 | 38.6 |
| 1994/5 | 660 | -47 | 19.4 | -27.6 | -1.4 | 34.0 |
| 1995/6 | 640 | -20 | 22.6 | 2.6 | 0.12 | 28.7 |

| Year | Recoverable reserves (bcm) | Net addition/ Depletion (bcm) | Production (bcm) | Gross addition to recoverable reserves (bcm) | Reserves replacement ratio* | Life of reserves (yrs current prodn.) |
|---|---|---|---|---|---|---|
| 1996/7 | 692 | 52 | 23.3 | 75.3 | 3.23 | - |
| 1997/8 | 675 | -17 | 26.4 | 9.4 | 0.36 | - |
| 1998/9 | 628 | -47 | 27.4 | -19.6 | 0.04 | - |
| 1999/0 | 647 | 19 | 28.4 | 9.4 | 0.33 | - |

* defined as ratio of gross addition of reserves to total production during year
Source: TERI Yearbook 2001/02, MoPNG Statistics 1998

***The decline in reserves over the past few years has been quite marked***

The decline in reserves during the 1990s was quite marked and can be attributed to a number of factors, chief amongst which are:

1) The most easily exploitable fields have already been found
2) Lack of exploration by the state-owned oil companies, due to a lack of funding and incentives, especially for gas
3) Lack of incentives offered by the Government of India to foreign companies, which have been reluctant to work in a difficult investment climate

While production levels from existing fields are expected to decline in the medium-term, recent discoveries should ensure that overall production can be maintained at a similar level.

## 4.7 Projected Gas Supply

The overall reserves life for India has been in decline since the early 1980’s and was at less than 29 years of current production by 1995/96. The largest producing fields, the Bombay High field (associated) and Bassein field (free gas), which combined currently provide almost **60%** of total gas production, are both in decline, as is production from the North and South Gujarat fields. The western onshore and offshore regions have been extensively explored and there is no indication of major new gas finds, although there may be opportunities for increasing production from some existing fields. The prospect of large increases in production from the Cauvery or Rajasthan regions is generally considered to be low. The joint venture fields of Tapti and Panna- Mukta will boost production, while bringing the new gas finds in the Krishna-Godavari basin onstream should ensure that gas production remains above 30 bcm until at least 2010

Table 4-6 Projected Gas Supply from India's Domestic Reserves (bcm)

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| Western Offshore | 16.7 | 16.0 | 14.4 | 13.7 | 12.0 | 10.4 | 9.0 | 7.7 | 6.9 |
| Western Offshore Joint Ventures | 6.3 | 6.3 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 | 6.1 | 6.1 |
| Gujarat | 3.9 | 3.7 | 3.2 | 2.9 | 2.6 | 2.7 | 2.5 | 2.3 | 2.2 |
| Rajasthan | 0.4 | 0.4 | 0.4 | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| North East | 4.1 | 4.2 | 4.4 | 4.5 | 4.4 | 4.7 | 4.6 | 4.6 | 4.6 |
| Krishna Godvari | 1.3 | 1.3 | 1.3 | 4.0 | 6.7 | 10.3 | 10.3 | 10.3 | 10.3 |
| Tamil Nadu | 0.7 | 0.7 | 0.7 | 0.7 | 0.7 | 0.8 | 0.7 | 0.7 | 0.7 |
| **Total** | **33.4** | **32.6** | **30.6** | **32.4** | **32.6** | **35.1** | **33.2** | **31.7** | **30.8** |

Source: MoPNG, India Natural Gas Development Plan, ADB, Nexant

There is considerable potential to develop supply from the north eastern region, principally Assam and Tripura, and there is a ready demand for this gas. A new exploration policy is under implementation and it is expected that this will stimulate greater interest in the Indian Exploration and Production (E&P) sector from the international oil industry. It is believed that some of the deeper offshore prospects, particularly off the south western and east coasts, may have potential to provide large reserves.

Other less conventional options for gas production are being pursued in India, notably coal bed methane (CBM) and gas hydrates. The long-term potential for coal bed methane from India's large coal deposits in the northern states and in Gujarat is considered to be good. At present, investigation is at the preliminary stage, with the first exploration licences issued this year. India is believed to have very significant gas hydrate deposits in the offshore regions, although it is recognised that development of gas from gas hydrates is in it's infancy worldwide and major technological challenges have to be overcome before commercial exploitation is a realistic possibility.

### 4.7.1 Imported Gas Supply - LNG

Although the LNG project at Dahej is underway, the stalling of the receiving terminal project at Dabhol means that uncertainty surrounds when LNG imports will begin. The long-term level of imports will depend upon the further development of these terminals, or the development of new terminals. (Generally it is much cheaper to add capacity to an existing terminal so it would be anticipated that Dabhol and Dahej terminals would be expanded to at least 10 MTPA before new terminals are built in the north west coast region.)

Projected LNG supplies to India, based upon existing contracts and NEXANT projections, are shown in the table below:

Table 4-7 Projected LNG Supply to India (mtpa)

| **Bcm/year Case** | **2003** | | **2006** | | **2011** | |
|---|---|---|---|---|---|---|
| | **Low** | **High** | **Low** | **High** | **Low** | **High** |
| **Project:** | | | | | | |
| Cochin | - | - | - | - | - | 2.5 |
| Dabhol | - | - | 1.25 | 2.5 | 2.5 | 5 |
| Dahej | - | - | 5 | 5 | 5 | 7.5 |
| **Total Supply** | **-** | **-** | **6.25** | **7.5** | **7.5** | **15** |

Source: Nexant

India's projected low and high LNG supply levels are shown in the table below in bcm:

Table 4-8 Projected LNG Supply to India to 2001 (bcm)

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| LNG Imports (Low) | - | - | 3.4 | 8.6 | 10.3 | 10.3 | 10.3 | 10.3 | 10.3 |
| LNG Imports (High) | - | - | 3.4 | 10.3 | 15.4 | 17.1 | 17.1 | 17.1 | 20.5 |

Source: Nexant

LNG projects, due to their high capital cost and complex linkages, have long gestation periods and it is unlikely that more than 3-4 terminals will be developed in India before 2011.

## 4.8 Gas Pricing

### 4.8.1 Consumer Pricing

The price of gas in India has historically been fixed by the Government, but prices are moving to internationally set parity pricing. The Indian Government has decided to deregulate the sector but it still has to appoint a gas regulator and develop the appropriate regulatory framework.

***Gas prices are moving to internationally set parity pricing.***

The pricing of gas in India will have a significant influence on future demand and supply. The key element of gas pricing is its deregulation and the establishment of a market related framework for consumers. During the period October 1997 – March 2000, the consumer price of gas was linked to the price of a basket of low sulphur and high sulphur fuel oils. By late 2003 the petroleum ministry plans to increase the gas price to **100%** parity with FO.

Table 4-9 Natural Gas Price as % of LS & HS Fuel Oil

| | 1997/98 | 1998/99 | 1999/00 |
|---|---|---|---|
| General Price | **55%** | **65%** | **75%** |
| Concessional price for the north-eastern region | **30%** | **40%** | **45%** |

Source: Petroleum Economist, Energy In the India Subcontinent, 2000 and TERI Energy Yearbook 2000

By 1999/2000 the general gas priced increased to **75%** of the FO price and the Gas Pricing Committee recommended that prices be increased so that they became at par with import LNG prices by 2002.

The price of gas produced from medium sized fields developed through joint ventures is already at the level of **100%** parity with fuel oil.

***New gas regulatory framework will have to consider trading, ownership, regulatory and pricing issues.***

Key issues for the future that the new gas regulatory framework will have to consider are: unbundling of trading and transmission, cross-ownership between distribution and transmission, fixing of transportation and distribution charges, regulation of the LNG sector, open access to pipelines, and pricing and allocation of natural gas to customers.

### 4.8.2 Transportation Prices

The transportation charge payable to GAIL along the HBJ pipeline is Rs. 1150/Mcm. The transportation charge will increase by **1%** for every **10%** increase in the consumer price index. This increase will be paid to GAIL out of the Gas Pool Account. The transportation charge will be linked to the calorific value of 8,500 kcal/cm until such time as it can be denominated in terms of calories.

In addition to the price as fixed above, the transportation charges and royalties, taxes, duties and other statutory levies on the production, transportation and sale of natural gas will be payable by the consumers. Out of the consumer prices collected by GAIL, GAIL will retain the amount required to pay for the higher cost of gas purchased from the JV Companies.

An amount of Rs. 250 crores per year will also be deducted by GAIL from the consumer revenues collected and credited to the Gas Pool Account to continue to compensate OIL for concessional gas prices in the north east. This is to compensate OIL for increases in the operating cost on account of inflation and for R&D on exploration and exploitation of small fields. Any balance amount left in the Gas Pool Account after taking care of the above requirements would be transferred to the Central Exchequer. For the purpose of compensating OIL for concessional gas prices in the north east, the producer price of OIL will be Rs. 1900/Mcm which will be increased by **1%** for every **10%** change in the consumer price index.

### 4.8.3 Producer Prices

The producer price of gas, payable to ONGC, is calculated on a netback basis by GAIL, with approval of the MoPNG, by deducting a contribution for the Gas Pool Account and the higher cost of JV gas from the cash flow based on the consumer prices. Subsequently, the floor price for ONGC gas has been retained as Rs 1,650/Mcm for 9,000 kcal/cm gas (or Rs 1,833/Mcm on 10,000 kcal/cm basis). This pricing is regarded as discriminatory by ONGC as the producer bears the full brunt of any fall in international fuel oil prices, while the transporter's prices and subsidies are protected.

ONGC/OIL and joint venture operations are permitted to sell gas from marginal isolated fields to be developed in future at market driven prices. Isolated and marginal fields are defined separately for onshore and offshore areas. The producer price realised for gas from the Tapti field has been reported as $3.11/MMBTU.

### 4.8.4 LNG Pricing

***LNG pricing may be set on a netback basis related to LNG term off-take contracts in the Pacific basin.***

One important feature on LNG imports into India will be the price. LNG pricing in the Pacific Basin is set by long-term contracts to Japan, Korea and Taiwan from producers in the Middle East and the Far East. It is the contracts from the Middle East which are key to India, as this is the obvious source of supply to the west coast. LNG pricing to India may be set on a netback basis related to these long-term contracts, which would imply prices to the west coast of India around $3/MMBTU, depending upon crude oil price levels.

## 4.9 Gas Demand

The existing demand for gas in India has been heavily constrained by supply. Gas usage is primarily for power and fertilisers in the Bombay area and along the HBJ pipeline route. Around **41%** of the gas produced feeds fertiliser plants, while power generation accounts for another **37%** of gas demand. The composition of demand in 2000 is shown in the table below:

Table 4-10 Natural Gas Consumption in India for 2000 (bcm)

***The gas demand is dominated by the power sector and fertiliser industry.***

| **Industry** | **Consumption (bcm)** | **Proportion of the total (%)** |
|---|---|---|
| Power generation | 9.14 | **38%** |
| Industrial fuel | 2.50 | **11%** |
| Tea plantation | 0.15 | **1%** |
| Domestic fuel | 0.26 | **1%** |
| Captive use/Liquefied petroleum gas | 0.90 | **4%** |
| Fertiliser industry | 8.91 | **37%** |
| Petrochemicals | 0.69 | **3%** |
| Others | 1.25 | **5%** |
| **Grand Total** | **23.8** | |

Source: TERI Energy Data Directory 2001/2002

Petrochemical usage is actually the shrinkage in the gas caused by the extraction of propane and butane at fractionation plants at the gas landfall and along the HBJ pipeline.

## 4.10 Projected Gas Demand

The ADB sponsored India Gas Development Master Plan indicates that when price sensitivity is incorporated into the demand picture the demand for gas will be around 92 bcm by 2011. The incremental demand, particularly in the 2002-2007 period, will be primarily in the west and north west of India in Maharashtra, Gujarat, and along the HBJ pipeline corridor to the Delhi region.

Table 4-11 Projected Gas Demand for India

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| Power | 28.2 | 32.8 | 37.5 | 42.1 | 46.8 | 52.5 | 58.2 | 63.8 | 69.5 |
| Fertiliser | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 | 13.8 |
| Industry | 6.2 | 6.2 | 6.2 | 6.2 | 6.2 | 6.2 | 6.2 | 6.2 | 6.2 |
| Other | 1.8 | 1.9 | 1.9 | 2.0 | 2.1 | 2.3 | 2.5 | 2.6 | 2.8 |
| Total | 50.0 | 54.7 | 59.4 | 64.2 | 68.9 | 74.8 | 80.6 | 86.5 | 92.4 |

Source: MoPNG, India Natural Gas Development Plan, ADB

***Gas demand is projected to rise by 80% in 8 years at current prices, but will be affected by any increase in the gas price.***

The projected gas demand to 2011 is shown in the table above. Gas demand is projected to rise to over 90 bcm by 2011 from 50 bcm in 2003, an increase of over **80%** in 8 years. This demand projection is the unconstrained demand, i.e. demand at existing prices and it is estimated that these demand figures may drop by **25%** for gas prices above $3/MMBTU, which is the range in which new sources of gas are likely to be priced. (Existing unconstrained demand projections conducted by GAIL, which are based upon current gas prices, show gas demand reaching 104 bcm by 2009 and 198 bcm by 2020).

The projected gas demand is principally driven by the pressing need for more power generation plant. It is in the power sector that the economic advantage of using gas is greatest. The liberalisation of gas prices may result in these levels of demand changing as the impact of the move towards market levels of gas prices is felt.

The demand for gas from the fertiliser sector will be limited to filling the existing plants to capacity (presently a number of plants are run on naphtha due to insufficient availability of gas). As in Bangladesh, the production of fertiliser from new plants is doubtful economically and there is a growing recognition that incremental fertiliser demand would most economically be sourced from countries where the gas feedstock is low cost, e.g. Saudi Arabia, Oman.

Given that power will be the principal driver of future gas demand, it is clear that the progress of liberalisation of the power sector will have a major bearing on overall gas demand.

## 4.11 Gas Supply/Demand Balance

The supply demand balance for India to 2011 shows a major gas shortfall between demand and domestic supply increasing from around 16 bcm in 2003 to over 60 bcm by 2011.

Table 4-12 Natural Gas Supply/Demand Balance for India to 2011 from Indigenous Supply

| Gas Supply | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| **Total Indigenous Supply** | 33.4 | 32.6 | 30.6 | 32.4 | 32.6 | 35.1 | 33.2 | 31.7 | 30.8 |
| **Total Demand** | 50.0 | 54.7 | 59.4 | 64.2 | 68.9 | 74.8 | 80.6 | 86.5 | 92.4 |
| **Supply Demand Balance** | **- 16.6** | **- 22.1** | **- 28.8** | **- 31.8** | **- 36.3** | **- 39.7** | **- 47.4** | **- 54.8** | **- 61.6** |

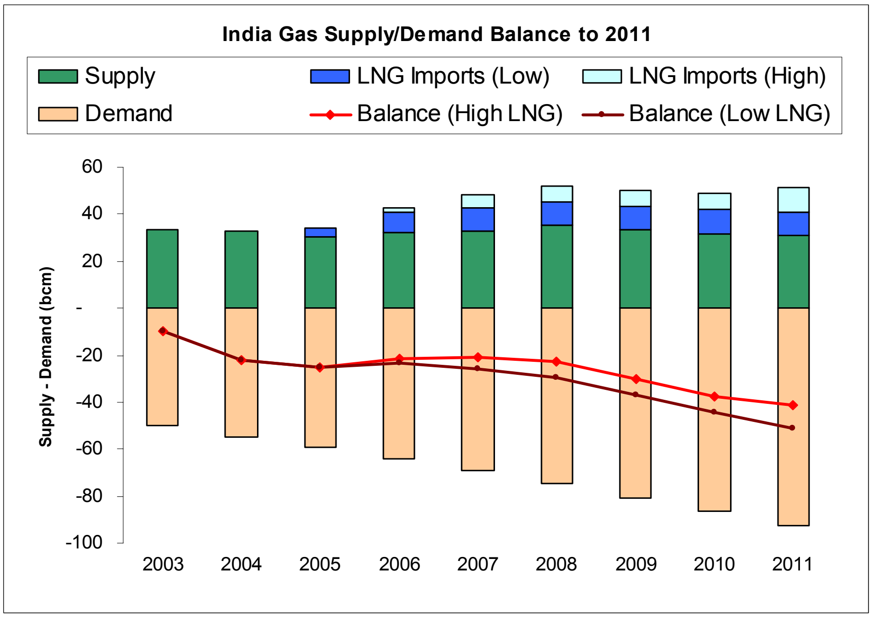
Source: MoPNG & Nexant

As discussed earlier, the demand projections are based upon existing prices, although demand may be reduced by up to **25%** as gas prices based upon higher cost imports enter the market. This will reduce the gas deficit but it will still be almost 40bcm by 2011.

This deficit will be taken up in part by LNG imports through the terminals currently under development. The table below shows the effect of the low and high LNG import scenarios on the gas balance. With the low scenario the deficit amounts to around 51 bcm, while with the high scenario it is around 41 bcm.

Table 4-13 Natural Gas Supply Demand Balance for India to 2011 including LNG Imports

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| Supply Demand Balance | - 16.6 | - 22.1 | - 28.8 | - 31.8 | - 36.3 | - 39.7 | - 47.4 | - 54.8 | - 61.6 |
| Projected LNG Imports (Low) | - | - | 3.4 | 8.6 | 10.3 | 10.3 | 10.3 | 10.3 | 10.3 |
| Projected LNG Imports (High) | - | - | 3.4 | 10.3 | 15.4 | 17.1 | 17.1 | 17.1 | 20.5 |
| **Balance (Low LNG)** | **- 16.6** | **- 22.1** | **-25.4** | **- 23.2** | **-26.0** | **- 29.4** | **- 37.1** | **- 44.5** | **- 51.3** |
| **Balance (High LNG)** | **- 16.6** | **- 22.1** | **-25.4** | **- 21.5** | **-20.9** | **- 22.6** | **- 30.3** | **- 37.7** | **- 41.1** |




Source: MoPNG & Nexant

Figure 4-5 India's Supply Demand Balance to 2011

***The liberalisation of prices may result in these levels of demand changing as the impact of the move to market level prices is felt.***

The liberalisation of prices may result in these levels of demand changing as the impact of the move to market level prices is felt. However, it remains certain, at least in the short to medium-term, that any significant expansion in demand will have to be met through the import of gas. Such imports, whether in the form of LNG or pipelines, will require anchor customers to be able to support such projects. The only customers in India able to provide this support are the power sector and the other major industrial consumers (e.g. fertiliser plants and the sponge-iron industry, although there is considerable doubt that the fertiliser sector could support substantially higher gas prices).

## 4.12 Summary

***Projected demand for gas is significantly greater than the projected supply and demand will have to be met through imports of gas.***

While recent gas finds should ensure that current production levels can be approximately maintained in the medium-term, it is clear that the projected demand for gas is significantly greater than the projected supply and that this gap will increase over the coming decade. Although new discoveries should negate the effect of declining production at existing fields, at least in the short to medium-term it is clear that any significant expansion in demand will have to be met by importing gas. Such imports, whether in the form of LNG or pipelines, will require anchor customers to be able to support such projects. The power sector and the other major industrial consumers in India, e.g. fertiliser plants and the sponge-iron industry, may be able to provide this guarantee, although it is doubtful whether the fertiliser industry would be able to support the higher gas prices expected to be associated with LNG projects.

Sri Lanka has no indigenous gas resources and is distant from regional sources of supply.

***The prime demand for natural gas in Sri Lanka will come from incremental power capacity additions.***

The prime demand for natural gas in Sri Lanka will come from incremental power capacity additions. (Most of Sri Lanka's existing thermal power capacity is based upon fuel oil, utilising the supply from the CPC refinery. This fuel oil capacity is fully utilised and any incremental demand will need to be imported.) Hydropower sources are largely utilised in the country and therefore natural gas, if available at a competitive price, would be a suitable fuel for power generation.

Power capacity development plans show that some 2,200 MW of incremental power will be required over the next 10 years. If this capacity were to be built using natural gas as the energy source, then the demand for natural gas would rise to 1.3 bcm by 2011. The projected demand is shown in the table below:

Table 5-1 Baseload Gas Demand for Sri Lanka (bcm)

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| **Gas Demand** | **0.20** | **0.27** | **0.42** | **0.59** | **0.66** | **0.84** | **1.03** | **1.22** | **1.33** |

There is at the present time little industry which would utilise significant quantities of gas, and industries currently using fuel oil switching to gas would leave Sri Lanka with surplus fuel oil to export, which would not be economically beneficial.

***The key problem for Sri Lanka is that the projected demand build up for gas is well below the level required to make traditional gas projects economic.***

The key problem for Sri Lanka is that the projected demand build up for gas is well below the level required to make traditional gas projects viable, both pipeline and liquefied natural gas (LNG).

However, recent technological developments may have the potential to provide gas at economic prices, namely smaller scale LNG projects and the supply of gas in compressed form by ship. In addition, there is the possibility of utilising regional gas sources via offshore pipelines from India. Each of these options is currently being analysed in a parallel study.

The overall gas balance for the SARI region shows a marked deficit which increases substantially over the next decade. Depending on the level of LNG imports to the region this deficit may increase to over 50 bcm by 2011.

Table 6-1 Gas Balance for SARI Region to 2011(bcm)

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|
| **India** | | | | | | | | | |
| Supply | 33.4 | 32.6 | 30.6 | 32.4 | 32.6 | 35.1 | 33.2 | 31.7 | 30.8 |
| Demand | 50.0 | 54.7 | 59.4 | 64.2 | 68.9 | 74.8 | 80.6 | 86.5 | 92.4 |
| LNG Imports (Low) | - | - | 3.4 | 8.6 | 10.3 | 10.3 | 10.3 | 10.3 | 10.3 |
| LNG Imports (High) | - | - | 3.4 | 10.3 | 15.4 | 17.1 | 17.1 | 17.1 | 20.5 |
| **Balance (Low LNG)** | **- 16.6** | **- 22.1** | **-25.4** | **- 23.2** | **-26.0** | **- 29.4** | **- 37.1** | **- 44.5** | **- 51.3** |
| **Balance (High LNG)** | **- 16.6** | **- 22.1** | **-25.4** | **- 21.5** | **-20.9** | **- 22.6** | **- 30.3** | **- 37.7** | **- 41.1** |
| **Bangladesh** | | | | | | | | | |
| Supply | 13.6 | 14.3 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 |
| Demand | 11.5 | 12.2 | 12.9 | 13.9 | 14.5 | 16.0 | 16.6 | 17.6 | 18.6 |
| **Balance** | **2.1** | **2.1** | **1.8** | **0.8** | **0.2** | **-1.3** | **-1.9** | **-2.9** | **-3.9** |
| **Sri Lanka** | | | | | | | | | |
| Demand | 0.2 | 0.3 | 0.4 | 0.6 | 0.7 | 0.8 | 1.0 | 1.2 | 1.3 |
| **Overall Regional Balance (Low LNG)** | **- 14.7** | **- 20.3** | **- 24.0** | **- 23.0** | **- 26.5** | **- 31.5** | **-40.0** | **-48.6** | **-56.5** |
| **Overall Regional Balance (High LNG)** | **- 14.7** | **- 20.3** | **- 24.0** | **- 21.3** | **- 21.4** | **- 24.7** | **-33.2** | **-41.8** | **-46.3** |

In considering the South Asia position on natural gas, it is important to understand the optimistic nature of the demand projections. The demand projections in India and Bangladesh do not take into account the new and inevitably higher pricing structures that will materialise. This is particularly true in India, where new demand will be filled by imported gas as indigenous resource development will be limited. Bangladesh gas demand will inevitably be slowed by lack of investment funding.

***Gas supply from domestic sources will slowly decline in India.***

On the supply side, the picture in India is fairly clear; gas from existing sources will slowly decline over the next decade, although recent finds will likely redress this balance. However, in Bangladesh the supply could be increased, the main constraint being a lack of new investment in E&P which is in turn due to a lack of economic markets for the gas.

The Indian gas picture is certainly one of a growing deficit. Bangladesh, although the projections show a deficit, would be in significant surplus if the demand projections fail to materialise, and this would be even greater if E&P development is vigorously undertaken. Sri Lanka figures represent only a small potential demand and then only if gas can be brought in at the right price.

***Overall the region will be in deficit for natural gas over the next 10 years.***

Overall, the region will be in deficit for natural gas over the next 10 years. The size of demand in India, even considering the reduction that may result due to higher priced gas, will certainly be larger than any surplus that may arise in Bangladesh.

There is a potential opportunity for gas trade from Bangladesh to India, and a small potential demand in Sri Lanka

***There is a possible regional opportunity for Bangladesh to sell gas to India, should the right circumstances prevail in Bangladesh.***

The SARI regional gas picture developed in the preceding sections clearly indicates that there is a possible regional opportunity for Bangladesh to sell gas to India, should the right circumstances prevail in Bangladesh.

There has been substantial interest from the international oil community in the development of pipelines from Bangladesh in India on the strength of some recent discoveries. It is fair to say that to date the same level of interest has not been shown by the state oil company in Bangladesh, Petrobangla, or indeed the Bangladeshi government. The prevailing feeling in Bangladesh is that there are insufficient reserves to support significant export projects. The discovery of new reserves is likely to go some way to change this view, particularly considering the need in Bangladesh for foreign currency earnings. There are several possible options for export from Bangladesh, by land into West Bengal and an offshore line from the Chittagong area to West Bengal.

***This presents significantly greater market risk than an import project to the western side of India.***

Bangladeshi gas would be brought into Eastern India, where the demand for gas is lower than the north and west of the country, and the competitive price is lower due to competition from adjacent coal producing areas. This presents significantly greater market risk than an import project to the western side of India. The entities necessary to support offtake agreements in the eastern states are generally less creditworthy, and some states, notably Bihar, would be able to give little credible support to a project.

***Both onshore and offshore pipelines carry construction risk due to the terrain to be crossed.***

Both onshore and offshore pipelines carry construction risk due to the terrain to be crossed. An onshore pipeline would traverse vast stretches of swamp and rivers while an offshore pipeline would have to span the Ganges fan. Detailed feasibility studies would be required for either onshore or offshore options, and experienced contractors would be required for construction and project management.

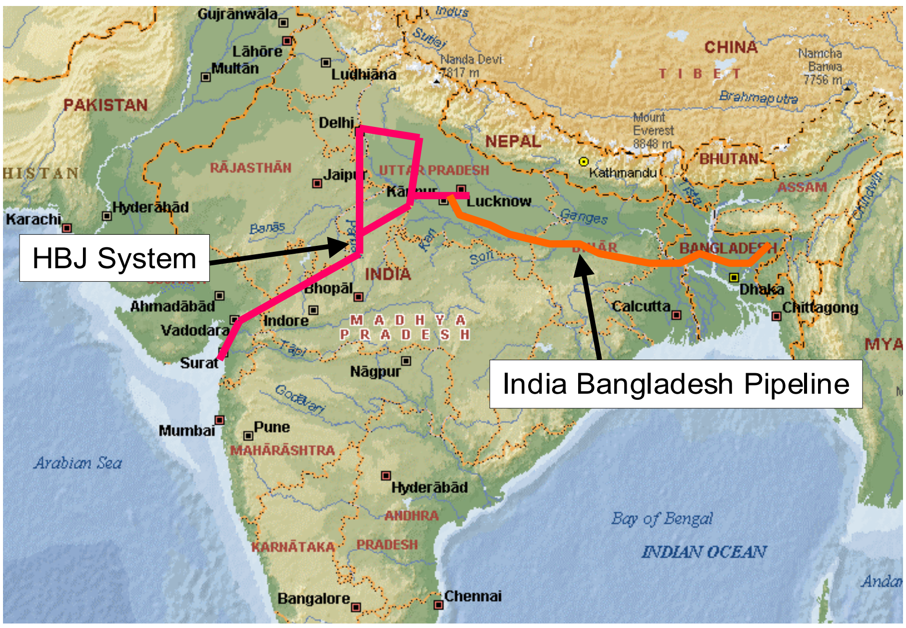



Figure 7.1 Possible onshore pipeline routing for Bangladesh India Pipeline

***The key for a successful gas pipeline project is in maximising the volumes carried, and the largest gas market customers in India are located in the west and the north of the country.***

The key for a successful gas pipeline project is in maximising the volumes carried, and the largest gas market customers in India are located in the west and the north of the country.

These markets would best be accessed by connecting a pipeline from Bangladesh to the HBJ pipeline system in Uttar Pradesh. This is a substantial distance from Bangladesh, over 1,300 km from the northern gas fields and a similar distance from Chittagong. The pipeline route would traverse the Jamuna river and significant distances of marsh and swamp. The cost of such a pipeline would be substantial and in order for it to be economic a minimum volume of around 5.1 bcm (500 MMSCFD) would be required. The total estimated cost for such a pipeline is estimated at $900 million.

The markets of Eastern India (West Bengal, Bihar) are closer but too small on their own to warrant the construction of a pipeline across Bangladesh. Gas sourced in Bangladesh could be delivered far down the eastern coast and into the eastern regions of India at prices cheaper than those possible using regasified LNG, if the input gas price into the pipeline was as low as that typically charged in the Gulf. However, it is certain than Bangladesh would insist on realising a much greater value for its gas than Gulf producers (it is a much scarcer resource than in the Gulf). At the present time, the sales gas price in Bangladesh has a floor of around $2.00/MMBTU, the price currently realised by joint venture E&P companies in Bangladesh. Bangladesh is likely to want a significant margin on the gas for export.

Assuming a gas input price of $2.00/MMBTU, sales gas ex-Bangladesh could be delivered to Kakinada in Andhra Pradesh at a price of around $3.45/MMBTU which would be competitive with regasified LNG at this point. However, gas imported from Bangladesh would be better used by preferentially supplying demand in the northern states, as the larger volumes that could be sold here would reduce the unit cost of transportation.

If gas were sourced from Bangladesh's offshore fields a gas pipeline to India could be routed offshore to reduce the distance. However, there are a number of technical issues to be resolved in any offshore route to India from this region. The route passes through areas of extremely high currents (2 m/s is indicated on the admiralty charts), requiring a detailed investigation of pipeline stability before the route can be confirmed. There are areas prone to seabed movement along the route and these should be surveyed and analysis undertaken to ensure that the pipeline can be routed safely through them. There is also a stretch along the route that contains steep sided canyons. These would cause problems for the installation of pipelines and detailed survey is required to investigate the stability of the slopes on the shelf above these canyons, where the pipeline is proposed to be laid. The route should avoid the numerous areas exhibiting heavy breakers during SW monsoons.

***A critical issue relating to the import of gas from Bangladesh is the availability of reserves and the willingness of the Government of Bangladesh/Petrobangla to make reserves available for export projects.***

A critical issue relating to the import of gas from Bangladesh is the availability of reserves and the willingness of the Government of Bangladesh/Petrobangla to make reserves available for export projects. A large pipeline project of 10 bcm would require dedicated reserves of at least 240 bcm (8.6 tcf), a minimum viable sized project would require over 4 tcf.

Given the existing mindset of the Government of Bangladesh, there will need to be significant new gas discoveries before reserves of this magnitude are set aside for export projects to India. Thus timing becomes an important issue. The latest exploration round in Bangladesh has been partially executed although there are still discussions over the blocks thought to be the most productive. A major discovery is likely to take several years to prove up and the development of a pipeline project at least two more years. If there is to be any gas export project from Bangladesh, this is not likely to be commissioned before at least 2005, and possibly much later.

***A clear and consistent regulatory framework governing the pipeline and agreed between India and Bangladesh.***

A clear and consistent regulatory framework governing the pipeline and agreement between the two governments will need to be established. All necessary permits and consents must be in place before lenders will loan to the project. The area of political risk on this project is small on an inter-country basis as there is no transit country and both exporter and importer have common interests in maximising the delivered gas volumes. A treaty will have to be established for the pipeline that includes international arbitration with no rights to block transit during dispute resolution.

## 8.1 Regional Gas Supply

***There are significant gas reserves in countries adjacent to South Asia that could be utilised to meet the import requirements indicated by the supply shortfall.***

There are significant gas reserves in countries adjacent to South Asia that could be utilised to meet the import requirements indicated by the supply shortfall. These reserves are principally in the Middle East, notably Iran and Qatar, in Turkmenistan in Central Asia and in South East Asia, in particular Indonesia, Malaysia and Australia. Bangladesh has had significant recent gas finds and could be a potential exporter to India. Myanmar is also a potential exporter.

Table 8-1 Proven Reserves of Major Gas Producing Countries in Asia and the Middle East

| Country | Proven Reserves (Bcm) | R/P Ratio (Years) |
|---|---|---|
| Iran | 23,000 | >100 |
| Qatar | 14,400 | >100 |
| Abu Dhabi | 6,010 | >100 |
| Turkmenistan | 2,860 | 57 |
| Indonesia | 2,620 | 42 |
| Australia | 2,550 | 78 |
| Malaysia | 2,120 | 45 |
| India | 880 | 31 |
| Oman | 830 | 62 |
| Bangladesh | 300 | 33 |

Source BP 2002, Nexant

Gas sources in Turkmenistan and Iran are relatively under-exploited, due mainly to political difficulties and the lack of gas export infrastructure. Other sources, such as Qatar, have only opened up to international markets relatively recently.

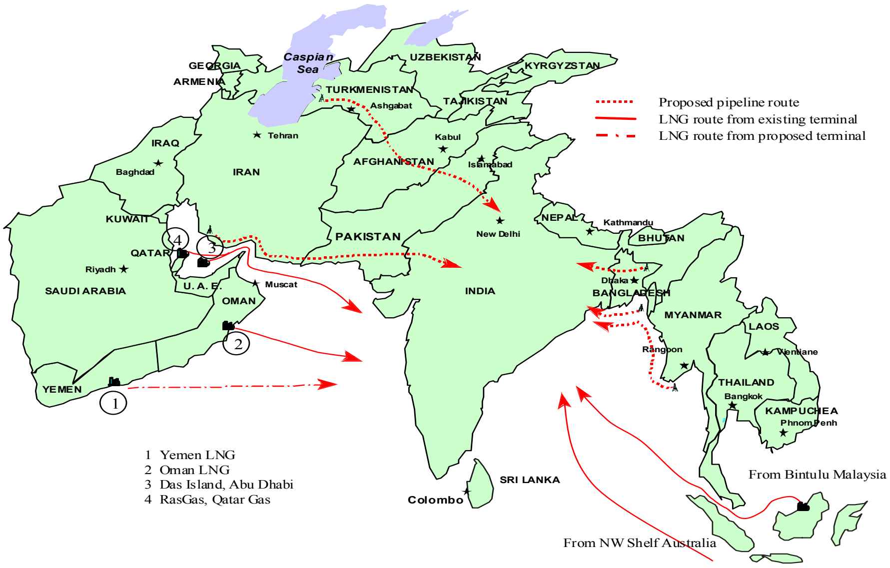



Figure 8.1 Principal Gas Imports Routes to Southeast Region

The economic attractiveness of one form of import over another depends on many factors, the key to which will be the distance to the end user and the price charged for gas into a pipeline or LNG liquefaction plant. For a pipeline project the transit tariff or fee that may be levied in intermediate countries will be a critical factor. Typically, pipelines are more economical over shorter distances (1,500 km off shore - 3,000 km onshore, depending on the volumes transported) and LNG more advantageous over greater distances.

## 8.2 Potential Suppliers of LNG

***There are a number of potential sources of LNG for South Asia: existing LNG plants that could be expanded and some greenfield projects.***

There are a number of potential sources of LNG for South Asia, some of which are existing LNG plants that could be expanded and some of which are greenfield projects. Clearly, the key factors are the distance from the region, the availability of gas and the price of the gas into the liquefaction plant.

Table 8-2 Distances in Nautical miles from existing LNG projects to Proposed Indian LNG terminals

| Exporter | Gujarat | Bombay | Cochin | Ennore/ Colombo | Calcutta |
|---|---|---|---|---|---|
| Oman | 853 | 853 | 1,301 | 1,900 | 2,819 |
| Qatar | 1,352 | 1,352 | 1,828 | 2,500 | 3,378 |
| Bontang (Indonesia) | 3,574 | 3,494 | 2,935 | 2,638 | 2,691 |
| Gorgon (Australia) | 3,702 | 3,702 | 3,125 | 3,025 | 3,256 |
| Arun (Indonesia) | 2,015 | 1,935 | 1,485 | 1,100 | 1,050 |
| Bintulu (Malaysia) | 2,820 | 2,740 | 2,120 | 2,008 | 2,160 |
| Yemen | 1,657 | 1,657 | 1,850 | 2,650 | 3,304 |

The table above shows the relative distances of key LNG projects from India. The west coast of India is closer to sources in the Gulf, although the east coast of India is closer to some South East Asian sources of gas. If the heavily depleted Arun field is disregarded, then some Gulf sourced LNG is similarly distant from east coast ports as that from S E Asia.

In a recent tender for LNG for terminals in Cochin and Dahej, Petronet LNG received bids from Australia, Indonesia, Malaysia, Qatar, Oman and Yemen.

Table 8-3 Asia Region LNG Projects

| Country | Name/Start-up | Current status | Operator | Capacity (mi TPA) |
|---|---|---|---|---|
| Qatar | Rasgas 1999 | LNG export plant in operation | Rasgas | 6.6 |
| | Qatargas 1997 | LNG export plant in operation | Qatargas | 7.7 |
| | Rasgas (Ras Laffan) 2003 | LNG export plant planned or proposed | Rasgas | 7.6 |
| Oman | OLNG (Qalhat) 2000 | LNG export plant in operation | Oman LNG | 6.6 |
| | OLNG T3 (Qalhat) 2004 | LNG export plant under construction | Oman LNG | 3.3 |
| Abu Dhabi | Adgas 1977, 1994 | LNG export plant in operation | ADGAS (Das Island) | 5.5 |
| Yemen | YLNG (Bal Haf LNG) | Speculative project | Yemen LNG | |
| Iran | - | Speculative project – Assaluyeh I | NIOC, BP, Reliance | |
| | - | Speculative project - Assaluyeh II | NIOC | |
| Australia | Northwest Shelf 1989 | LNG export plant in operation | Woodside Offshore Petroleum PTY Ltd | 7.5 |
| | Northwest Shelf T4 2004 | LNG export plant under construction | 2004 | 4.2 |
| | Northwest Shelf T5 2005+ | LNG plant planned or proposed | Woodside Offshore Petroleum PTY Ltd | |
| | Gorgon LNG | LNG plant planned or proposed | Chevron | 4.0 |
| | Bayu-Undan 2005+ | LNG plant planned or proposed | Phillips | 3.0 |
| | North Australia LNG 2007+ | LNG plant planned or proposed | Woodside Offshore Petroleum PTY Ltd | 7.5 |
| Indonesia | Arun Phase I – III (ACEH) 1978, 1984, 1986 | LNG export plant in operation | PT Arun NGL | 12.3 |
| | Natuna | Speculative project | | |
| | Bontang A-H (East Kalimantan) 1977, 83, 89, 93, 98, 2000 | LNG export plant in operation | PT Badak NGL | 22.0 |
| | Bontang I 2005 | LNG export plant planned or proposed | PT Badak NGL | 3 |
| | Tangguh (Irian Jaya) 2006 | LNG export plant planned or proposed | BP | - |

| Country | Name/Start-up | Current status | Operator | Capacity (mi TPA) |
|---|---|---|---|---|
| Malaysia | Bintulu MLNG I 1983 | LNG export plant in operation | MLNG 1 | 7.6 |
| | Bintulu MLNG II (DUA) 1995 | LNG export plant in operation | MLNG 2 | 7.8 |
| | Bintulu MLNG III 2003 | LNG export plant under construction | MLNG 3 | 6.8 |

Source: Nexant, Petroleum Economist – World LNG Map 2001 edition

### 8.2.1 Qatar

The North field, which spans Qatari and Iranian international boundaries, is one of the largest gas fields in the world. The first project, QatarGas, became operational in 1997 while the first phase of the RasGas project was completed in 1999. The RasGas project is currently being expanded by a further two trains, due to begin production in 2004, taking the total Qatari LNG liquefaction capacity to around 24 MMTPA

Given the huge gas reserves in Qatar, there is clearly opportunity to develop further LNG liquefaction capacity.

### 8.2.2 Oman

Oman has proven gas reserves of around 30 Tcf and began producing LNG from its Oman LNG project in 2000. The liquefaction plant has a current capacity of about 7 mtpa (6.6 mtpa nameplate) from two trains. A third train is being built with a capacity of 3.3 mtpa, due to begin production in 2006, while a fourth train is also reportedly under consideration.

### 8.2.3 Iran

There are at present no LNG projects in Iran, however given the vast gas reserves there is significant opportunity for projects to be developed. (Iran shares the massive North field with Qatar). Iran has announced plans for four LNG projects at Assaluyeh as part of Phases 11 to 13 of the South Pars Field Development. However, it is unlikely that Iran will be able to develop 4 LNG projects in anything except the very long term.

### 8.2.4 Abu Dhabi

The Adgas LNG project at Das Island in Abu Dhabi is the oldest LNG project in the Gulf. Originally commissioned in 1977 the plant was expanded in 1994 and now supplies 5 MMTPA to Japan on long-term contracts.

At the time of writing (check) are rumoured to have In addition to the 1.7 MMTPA contracted from Oman LNG, Enron signed up 0.5 MMTPA from Abu Dhabi to supply its ill-fated Dabhol project.

### 8.2.5 Yemen

A consortium including TotalFinaElf, Yemen Gas Company, Hunt, and ExxonMobil was due to complete construction on a 5.3 mtpa liquefaction facility by 2006. The project has been repeatedly delayed in the absence of firm buyers and concerns with the local security situation, prompting ExxonMobil and Hunt to recently pull out of the project. The option of suspending the project for five years has been discussed, casting severe doubt on whether or not this venture will be realised.

### 8.2.6 Australia

LNG projects in Australia are well established supplying to Japanese markets. The existing LNG liquefaction facility is the North West Shelf project, which has been producing LNG since 1989. A fourth train is currently under construction, which will increase the overall capacity of the plant to 11.7 MMTPA, while a decision on a fifth train is expected by 2004.

In addition to the operational projects there are a number of other projects under consideration at varying stages of development.

### 8.2.7 Indonesia

Indonesia is the world’s largest exporter of LNG, the total traded volume in 2001 being 23.2 MMTPA. LNG has been exported from Indonesia since 1977 from the Bontang terminal in East Kalimantan and since 1978 from the Arun field in the Aceh province of Sumatra.

The Arun project is fully exploited in terms of reserves available, and it is believed that there is little scope for expanding the Bontang projects further. There are significant gas deposits at the offshore Natuna gas field in the South China Sea but proposals for an LNG project have been hampered by the high quantities of $CO_2$ associated with the gas.

An LNG project is also under development at the Tangguh gas field in Irian Jaya. A 6 MMTPA 2 train project has been proposed, while a firm sales contract has been secured from China for a significant portion of the first train’s output.

### 8.2.8 Malaysia

Malaysia has exported LNG since 1983 from the Bintulu MLNG 1, of capacity 8 MMTPA, complex in Sarawak, on the island of Borneo. A second project MLNG 2, of 7.8 MMTPA capacity, was commissioned in 1995.

Malaysia is adding substantial LNG through the Bintulu MLNG 3 project. The project is considered by the operator Petronas to be a grassroots facility, but in reality it shares extensive facilities with earlier MLNG 1 & 2. The new two-train, 6.8 MMTPA project will bring the Bintulu complex up to 22.7 MMTPA capacity when fully completed, making it the biggest complex in the world. Commissioning of the first train of the expansion has recently taken place.

## 8.3 Potential Regional Gas Pipeline Projects

*There have been a number of import pipeline rotes.*

There have been a number of import pipeline routes mooted for gas supply into South Asia. Amongst these have been:

- Iran – Pakistan - India onshore
- Iran – Pakistan - India offshore
- Bangladesh - India onshore
- Bangladesh - India offshore
- Turkmenistan - Afghanistan - Pakistan - India
- Oman – India deep water

*Each of these projects has its own particular intrinsic technical difficulties and political difficulties.*

Each of these projects has its own particular intrinsic technical difficulties, and in addition the Government of India has some difficulties in political relations with most of the supply/transit countries.

### 8.3.1 Iran – Pakistan – India

#### Iran - India Onshore Pipeline

*An obvious supply option for India would be a pipeline from Iran.*

An obvious supply option for India would be a pipeline from Iran, crossing Pakistan and entering India in the western Rajasthan region, although it should be noted that this is a significant distance of around 2,400 km. Such an idea has been mooted many times, but the long standing difficult relationship between India and Pakistan has thus far impeded progress. In order to determine the costs involved the project team selected a routing from Iran to India and conducted a hydraulic analysis to determine the line sizing and compression required.

A discounted cash flow analysis at **10%** discount rate with a project life of 24 years using typical operating costs reveals that the marginal tariff for a volume of 27.4 MMcm/day would be $2.19/MMBTU. The delivered cost of gas would of course depend on the price of gas into the pipeline and any tariff levied by intermediate parties. However it is not unreasonable to assume that large volumes gas could be delivered to India for less than $3.00/MMBTU, as gas in the Gulf area is typically priced from $0.5/MMBTU – $0.75/MMBTU. (The gas price for a proposed Indian promoted fertiliser plant at Queshm Island in Iran is reported to be $0.75/MMBTU).

A similar analysis was conducted for a much larger volume of gas, 84 MMcm/day, and for this volume gas could be transported to India for around $1.32/MMBTU.

#### Iran – India Offshore Pipeline

The governments of India and Iran signed a Memorandum of Understanding (MoU) in 1993 to develop a project to transport 50-75

MMcm/day of gas via a pipeline on an offshore route outside of the territorial waters of Pakistan landing in Kutch in India. The feasibility study was launched in early 1995, but so far work has not started as permission has not been granted for offshore surveys in the waters of Pakistan. Clearly the acceptability of installing a pipeline within the Pakistan EEZ (extended economic zone) requires confirmation before a pipeline route can be considered in the shallower waters.

A pipeline route avoiding the Pakistan EEZ will traverse areas of rock outcrops, steep slopes and canyons, and would require a significant amount of investigation in order to investigate whether an acceptable pipeline route can be identified. There is a possibility of the pipeline requiring installation in water depths of approximately 1,000 m, which will impose a limit on the diameter of the pipeline that can be installed. Depending on the required flow rate, it may be necessary to install two smaller diameter pipelines in order to utilise currently available installation vessels. In addition, the Makran coast offshore Iran and Pakistan exhibits seismic action because of the differential plate movement and this would require detailed investigation.

It is certain that the deepwater routing will have a very high capital cost, although without any knowledge of the routing, water depth, corresponding seabed conditions etc. it is extremely difficult to estimate any meaningful capital costs. The calculation of a long run marginal tariff is therefore not possible.

The shallow water option will obviously require the co-operation of the Government of Pakistan before any pipeline project can be considered. Given the technical challenges involved and the offshore routing, it is certain that the cost will be substantially higher than the onshore pipeline option, therefore gas will be provided at a higher delivered cost than the onshore route considered above.

Given the enormous gas reserves base in Iran, the project risks associated with security of supply are relatively small. To support even the largest of potential projects, with a supply of 84 MMcm/day, the reserves requirement of around 740 bcm is small compared to the total proven reserves in excess of 23,000 bcm.

The largest area of risk on this project is political risk, the prospect of interruption of supply by Iran, or the increase of transit fees by Pakistan. A treaty will have to be established for the pipeline that includes international arbitration with no rights to block transit during dispute resolution. At the present time the U.S. sanctions on Iran would preclude the involvement of U.S. companies, and also lending from multi-lateral institutions such as the World Bank and the Asian Development Bank, which could be critical in giving comfort to other lenders.

There is a precedent for the brokering of agreements for the utilisation of resources between Pakistan and India. In 1960 the Indus water treaty was signed between India and Pakistan, an agreement on the sharing of water from the Indus river system. This system is still in place to day and has never been breached by either side. The agreement was brokered by the World Bank, which was able to act as intermediary in the negotiations. The example of the Indus water treaty shows that where the benefits of an agreement are plentiful and pressing, political barriers can be overcome. Multilateral organisations such as the World Bank and the Asian Development Bank have a key role in facilitating such negotiations. It should be noted that this negotiation is unlikely to be quick. The Indus water treaty negotiations took some 8 years.

### 8.3.2 Myanmar to India

Brown & Root have put forward proposals for a pipeline utilising gas reserves in Myanmar and Bangladesh. The initial proposals for offshore import projects of gas from Bangladesh and Myanmar would land gas in the Bay of Bengal area. They envisage an initial capacity of 28 MMcm/day, which could be increased by **50%** by extra compression. The total length would be in the order of 2,800 km including some 600 km offshore.

The projected transport cost of the landed gas is $1.0 - $1.6/MMBTU from Bangladesh, and $1.8 - $2.4/MMBTU from Myanmar. It should be noted that these figures do not include any tariffs that may be levied en route, nor do they account for the cost of gas into the pipeline. The implementation of such a project is estimated at 5-6 years.

As with gas export projects from Bangladesh, there would, at the present time, be concerns over the adequacy of reserves to support a major project and these reserves would have to be proven up, certified and assigned to a project in order to provide bankable support. As with Bangladeshi gas, gas from Myanmar would be brought into eastern India, where the market for gas is less attractive and creditworthy than the west of India.

The construction of an offshore pipeline 1,100 km along the Myanmar coast would be a substantial technical challenge, and as with an offshore line from Bangladesh would necessitate crossing the Ganges fan, which entails significant technical risk. Internationally recognised expertise in offshore pipeline construction and management would be required

If the pipeline passes through the territorial waters of Bangladesh, a trilateral treaty between India, Myanmar and Bangladesh would be required. At the present time, financing for a project in Myanmar would be extremely difficult given the opposition amongst the West to the existing political regime.

### 8.3.3 India – Oman Pipeline Route

The Oman-India project was conceived as a mega-project involving the supply of 56 MMcm/day by two subsea pipelines via a deep-sea route, outside the Pakistan EEZ, to India. The pipeline would be laid in 3,500 m of water, which would represent a significant technical challenge as no pipelines have thus far been laid at these depths. (Recently flow lines offshore Brazil have been laid to 2,000m+). There has been much speculation on the degree to which the technical feasibility of this project has been established. The common view within the industry is that much work still needs to be done to establish the technical viability of pipe-laying and of the intervention systems required for repair and maintenance of lines in this depth of water.

A second issue surrounding this project is the availability of proven reserves in Oman to support such a project, now that the Oman LNG project has been executed. There is a significant question mark over the adequacy of proven reserves.

The gas pricing of this project was to be indexed to crude oil. The "Agreement on Principal Terms" for the Oman – India gas pipeline the base price delivered at Bachau in Kutch was $2.4/MMBTU at crude oil prices of $15/bbl and $2.6/MMBTU at crude prices of $18/bbl.

### 8.3.4 Turkmenistan - Afghanistan - Pakistan - India Pipeline

Unocal led a consortium, Central Asia Gas Pipeline Limited, CentGas, to develop a $ 2 billion, 1,270 km mile long pipeline system to deliver natural gas from Turkmenistan's Dauletabad field to markets in Northern Pakistan, with a potential for a 640 km extension from Multan to New Delhi, India.

Studies revealed no unusual engineering challenges, and construction was expected to take 2 years. The pipeline is to be buried at an average depth of 1m using conventional technology. Approximately 830 km of the total pipeline route, including the Turkmenistan portion, lie in flat and rolling terrain. The remainder is routed through mountainous terrain. Average elevation is 1,218m, with a maximum elevation at 7,000 feet in Pakistan's Hindukush Range. The expected capacity was planned to be approximately 15-20 bcm per annum. The project sponsors projected a delivered gas price in Pakistan of $1.60/MMBTU to $2.05/MMBTU, on a fuel gas linkage.

This project faces numerous political difficulties at the present time, not least due to uncertainties related to the situation in Afghanistan. Although Agreements were signed in May 1997 between Pakistan and Turkmenistan covering construction from Turkmenistan via Afghanistan to the Pakistani city of Multan, the project faces problems and possible delays because of the ongoing political unrest in Afghanistan. By late 1998 Unocal pulled out of the CentGas consortium due to the difficulties associated with financing this project.

Turkmenistan has huge gas reserves and could certainly provide sufficient comfort to a project in terms of supply security. A pipeline from Turkmenistan would feed in North Western India where there is proven demand at market prices, and suitable guarantors for offtake security.

This project is inherently difficult, passing as it does across two transit countries to reach India, neighbours who each have a history of fractious relations with each other. The prime issue in risk mitigation is the transit of the pipeline through Afghanistan, which is highly unstable and subject to sporadic internal insurrection. This threatens the daily operation of the pipeline and fosters a lack of the confidence in the regulatory climate, and also raises the fear of political intervention in project operations. The political climate in Afghanistan will have to stabilise before such a project can be seriously contemplated. It is precisely this issue which has seen the withdrawal of major sponsors from the project.

The SARI region is relatively poor in natural gas resources relative to both the landmass and population size. India has proven natural gas resources of 880 bcm and Bangladesh 300 bcm. Whilst Indian production from existing fields is already peaking and is expected to decline quite rapidly over the next 5 years, gas from recent discoveries should enable current production levels to be maintained.

Although projections show Bangladesh going into gas deficit in 2008, the reality is that gas demand is highly unlikely to develop as projected, and it is likely that Bangladesh's current proven gas reserves will last at least 20 years providing domestic supply, and probably significantly longer. In addition, there is a very large upside potential for further growth of the reserves base, possibly up to 40 tcf. This will require additional exploration and investment work, the bulk of which is likely to come from international oil companies. Presently this potential is being stymied by an inability of the existing international players to get their gas to market.

***The demand for gas in India is already well in excess of supply, and this situation is set to increase as demand grows***

The demand for gas in India is already well in excess of supply and this situation is set to increase as demand grows. The introduction of LNG into the west of India over the next few years will alleviate the supply shortfall in the short-term, but further sources of gas will be required to meet India's needs in the medium and long-term. There is an opportunity for Bangladesh to monetize its gas assets by means of an export project to India. This faces political obstacles in view of the Bangladeshi government's desire to keep the resources for domestic use and also development challenges in the magnitude of a project that would be needed to get the gas to the distant north/west India markets.

***The projected shortfalls in gas supply in the north west, western and southern regions of India will only be met in the short to medium term by LNG supplies.***

The projected shortfalls in gas supply in the north west and western regions of India will likely only be met in the short to medium-term by LNG supplies. In the longer-term, the supply of gas through (or around) Pakistan may become a possibility to support demand in the north west of the country. The projected supply shortfalls on the eastern side of India (in the medium to longer-term) could be met best by supply from Bangladesh, if sufficient reserves are discovered and proved up, and the governments of Bangladesh and India are able to agree mutually acceptable terms.

***Pipelines would be viable from Iran or Turkmenistan but there are enormous political challenges.***

The Asian region has substantial reserves of gas that could be imported into the SARI sub-region by pipelines or LNG. Pipelines would be viable from Iran or Turkmenistan but there are enormous political challenges to be overcome in laying pipelines that cross Afghanistan and/or Pakistan. LNG supply to the SARI sub-region is attractive for Middle East suppliers as the logistics are much more favourable than for the Far East markets. LNG projects continue to be planned in the Middle East, most notably in Iran, although financing could be problematic.

The introduction of imported gas into the region will bring with it pricing dilemmas, as the cost of imported gas will be significantly higher than gas sold in the region at the present time. These issues have yet to be resolved.