Challenges and Perspectives for the Indian Gas Market

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Background

India has the potential to be one of the fastest growing gas markets in the world over the next 25 years. As of 2009, the share of natural gas was only 7% in India's primary energy supply, which remains largely dominated by coal (42%), biomass and waste (24%) and oil (24%). According to preliminary forecasts for the XII Five Year Plan, Indian gas demand could double between FY 2012/13 and FY 2016/17. The main challenge is to find enough supplies, both on the domestic side and on the import side. Indeed, consumption has been for a long time constrained by the lack of supply, with a gas demand potential estimated to be 20 bcm or 30 bcm higher than actual use (MoPNG, 2000). To address this supply shortfall, the Indian government introduced reforms as soon as end of the 1990s in order to encourage domestic production and the construction of liquefied natural gas (LNG) terminals. In particular, the New Exploration Licensing Policy (NELP) opened Exploration & Production to private and foreign companies. This appeared to be relatively successful: while gas production had been almost flat over a decade until 2009, it started to increase following the start of the Krishna Godavari KG-D6 field in April 2009. But after a year of growth, production of the field has been stagnating and even dropping, leaving India searching for gas supplies on global LNG markets.

India is very much a market in transition; and this is particularly the case for its gas market at all stages: policy, regulation and role of the State, and prices. While the years 2009 and 2010 appeared as a major step in the development of the Indian gas market, more needs to be done if the demand level of the next Five Year Plan is to be reached, as it implies a strong growth of imports as well as investments in production and import infrastructure.

India's natural gas market is a very price sensitive market as the ability of customers to absorb high prices differs between sectors. The power generation and fertiliser sectors – currently the main consumers – have been protected from high prices, quite often with below cost gas prices. They were allocated gas at low Administrative Price Mechanism (APM) prices determined by the government, but the recent pricing reforms that took place mid-2010 means the end of low APM prices, and that new gas supplies are likely to be more expensive. Fertiliser producers are also subsidised by the government and there are questions on their ability to absorb higher prices. In the power generation sector, the key factor is the competition between the incumbent fuel, coal, and its challenger, gas, in particular for base-load generation. Any change in the power sector or in coal markets will have a huge impact on whether gas is used as a base-load option or only for peak purposes, and therefore on future gas demand in the power sector. City gas and industrial users show greater price flexibility, but they are still emerging markets. Historically, gas had been allocated in priority to fertiliser and power plants, while city gas, compressed natural gas (CNG) and industrial had the remainder.

The Indian gas sector, like the whole energy sector, is still relatively dominated by state-owned companies. Oil and Natural Gas Corporation (ONGC) and Oil India Ltd (OIL) have dominant upstream positions, while until 2006, Gas Authority of India Ltd (GAIL) alone had been responsible for pipeline gas transport. The state has also a very important role in the regulatory framework and gas policy, in particular the allocation and pricing of gas. Recent reforms have brought more private investors in the upstream and downstream sectors, but a more transparent regulatory framework will be critical to incentivise future private investments. After the 2010 reforms, challenges remain. The dramatic increase of domestic production has been relatively short-lived, and the tough battle over the allocation and the pricing of KG-D6 gas, could have consequences on investments. In order for the Indian gas market to reach its potential, there are still many hurdles to be solved on pricing, supply, infrastructure, regulation and policy.

- **Insufficient supplies**. Insufficient supplies remain on top of the agenda despite a relative improvement. In order to prevent gas demand from being constrained by the lack of gas supplies, a dual move needs to be performed: increasing gas production and bringing additional supplies, either LNG or pipeline gas. Domestic production is expected to continue to represent most of India's supplies, and developing domestic gas resources is therefore critical to increase supplies to the Indian market. Despite the success of NELP in terms of discoveries, there remain some shortcomings, for example the low presence of IOCs. The upstream sector is changing though, from being dominated by NOCs, to JVs and private companies representing a growing share of domestic production. India is also likely to become more import dependent, and needs to build the necessary infrastructure, as well as attract the corresponding supplies – essentially a pricing issue. India is surrounded by countries with large reserves of gas: Russia, Iran, Qatar and Turkmenistan. Pipelines from Iran and Turkmenistan are currently being investigated, while India imports significant quantities of LNG from Qatar.

- **Gas pricing**. Pricing affects both the demand side (notably the fertiliser and power sectors) and the supply side, *i.e.* the development of the upstream sector and the ability of India to compete and attract new imports. India has a rather unusual dual gas pricing system, with APM gas produced by state-owned companies and non-APM gas from private companies and joint ventures (JVs). Until mid-2010, prices differed widely from around USD 2/MBtu for APM gas to almost USD 6/MBtu for the most expensive non-APM gas. This compared to LNG acquired sometimes at international gas prices (around USD 10/MBtu in 2010). Such a gap was pushing towards changes. Additionally, keeping domestic gas prices low would act as a disincentive for more upstream investment and threatens the growth of the Indian gas market. The declining availability of APM gas combined with the increase of privately produced gas was one of the triggers of the new reform. Two major changes took place in May 2010. The first was the radical increase of APM prices from USD 1.8/MBtu to USD 4.2 MBtu, while ONGC and OIL were allowed to market gas discovered in new fields allocated to them at market prices. This is an important step forward in order to encourage further investments in the upstream sector. Additionally, India will have to be an attractive market for future LNG or pipeline suppliers. The recent tightening of gas markets and competition from China as well as from historical LNG importers such as Japan and Korea has led to a sharp increase of international LNG prices. India may have enjoyed the consequences of the gas glut in 2009 and the availability of LNG at USD 4-5/MBtu, but this is over as of early 2012 with spot prices reaching USD 18/MBtu. Crucially, there is also no spot market in Asia that would provide a viable alternative to oil indexation, on which most of the new Australian projects coming on line towards the middle of the decade are based. The second decision taken in 2010 was the verdict of the Supreme Court on the price at which RIL was to sell its KG-D6 gas to RNRL: the government has the right to fix the price in the Production Sharing Contract (PSC) (fixed at USD 4.2/MBtu) when an arm-lengths price is impossible to find. It remains to be seen whether or not such a decision could deter private or foreign upstream investment.

- **Regulation and policy**. The downstream market remains relatively underdeveloped, and tackling this issue implies to attract investments from both public and private companies to develop the transmission, distribution and retail business. However, private companies need a stable and transparent regulatory framework and an equal treatment compared to state-owned companies. The Petroleum and Natural Gas Regulatory Board (PNGRB) Act (2006) is a step in the right direction. A key question is now to what extent the Board's powers will be further enhanced, which implies to clearly define its role and powers in downstream markets – regulation of transmission, LNG, or city gas.
- **Transmission/infrastructure**. Many cities do not have access to gas supplies, due to the lack of transmission network, notably in the East and South. Until 2008, the market was concentrated in the northwest of India. This changed with the construction of the East-West pipeline between the new production basin of Krishna-Godavari on the East coast and the existing market in the West. This also enabled many users along the pipeline to be connected. The diversification of supply entry points provides an opportunity to further develop the use of gas by extending the transmission infrastructure to new cities. In both cases, the regulatory framework, in particular transport tariffs, should give adequate incentives for the new infrastructure to be built.

Aims

The Indian energy and gas markets are at a crossroads in 2012. Energy requirements are expected to go strongly due to a growing economy and population increase. This paper aims at analysing the challenges current faced by the Indian gas industry, ranging from further increasing domestic production (both conventional and unconventional), attracting both new LNG and pipeline supplies and enhancing the transmission network, as well as tackling gas pricing and regulatory uncertainty issues. After reviewing the latest gas market developments, it looks at prospects on the supply and demand side in the light of recent gas pricing reforms and evolution of global gas markets. The supply side is key to understand the future production developments – conventional gas resources, shale gas, and CBM – and import increases based on LNG and pipeline gas. Sectoral gas demand is analysed with a special emphasis on the power sector and the competition between gas and coal based on levelised costs of electricity, but also on the transport sector. More than any other, the power sector crystallises India's current issues with the need to address energy poverty, achieve CO_2 emissions reductions while also meeting the predicted growth in demand. In that respect, gas has certainly a role to play.

Results

1. Industry structure

Each national gas market, and the issues that it faces or the successes it enjoys at a given point in time, are often a legacy of its historical development in terms of policy and market structure. It is therefore crucial, not only for India but also for any market, to look in depth at its historical development: market players, the importance of state-owned companies versus private players, the interaction between the state, its agencies, ministries and the gas industry players, as well as the key policy decisions taken to frame the gas market.

The Indian energy (and gas) industry has been historically developed based on state-owned companies, notably ONGC, OIL and GAIL. The past decade has seen the progressive entrance of new private foreign and Indian companies on the back of reforms taken by the government, but the conditions under which they operate are difficult, due to government interventions on gas prices and gas volumes allocation, the pricing system and the lack of a transparent, predictable and stable regulatory framework.

<u>1.1 India's gas industry during the 19th-20th century</u>

The development of India's oil and gas industry started after the independence of India. Although exploration and production activities started in the 19th century (the first well was drilled in 1866 and the first commercial discovery was made in 1889 in Digboi), activities were limited to the Assam Oil Company and Attock Oil. In 1948, the Government of India (GoI) enacted the Industrial Policy Statement calling for the development of its petroleum industry. The first steps were actually conducted by private companies: Burmah Oil Company/Assam Oil Company (BOC/AOC). This started to change in 1955, when GoI decided to develop oil and gas resources, and created an Oil and Natural Gas Directorate (ONGD), which would ultimately become the current ONGC. ONGD depended on the then Ministry of Natural Resources and Scientific Research. In 1956, the GoI adopted the Industrial Policy Resolution and ONGD became a Commission: ONGC. OIL India Private Ltd was created in 1959, with two thirds owned by BOC/AOC and the rest by GoI; in 1961, it became a Joint Venture (JV) and GoI's share increased to 50%, and a wholly state-owned company in 1981. OIL started producing gas in 1959, followed by ONGC in 1964.

The gas market was nevertheless very immature until the 1970s. Things started to change when ONGC's Bombay High started producing in 1974. In 1984, another state-owned company, GAIL, was created to develop the midstream and downstream sectors. One of its first achievements was the first major transregional pipeline, the Hazira-Vijaipur-Jagdishpur (HVJ) completed in 1991. Until 1991, India's gas market was in the hands of these three state-owned companies. But that year, India started to liberalise its economy and in particular, to deregulate the gas sector, a move which was not unique to the country as it had been observed in others, notably the United States and the United Kingdom.

In 1993, an upstream regulator was created, the Directorate General of Hydrocarbons (DGH), but no downstream regulator was created. In 1994, ONGC was reorganised as a public company and GoI divested 2% of its share through competitive bidding. In 1999, 10% was sold to India Oil Corporation (IOC) and 2.5% to GAIL. The key step was nevertheless the NELP, which started in 1997, opening the upstream sector to private and foreign companies via licensing rounds. As of today, a few private players and foreign companies have entered the Indian gas market in different parts of the gas value chain (upstream, transmission, LNG terminals, and distribution). RIL, active in upstream, transmission and distribution, is the most notorious example.

1.2 Key entities

GoI plays a key role in different energy sectors through dedicated ministries. A total of five ministries or departments oversee the energy sector: the Ministry of Power, the Ministry of Coal, the Ministry of Petroleum and Natural Gas, the Ministry of New and Renewable Energy and the Department of Atomic Energy. Two regulators now exist for the upstream and downstream oil and gas sectors.

- The Ministry of Petroleum and Natural Gas (MoPNG) oversees the exploration and production of oil and natural gas; their refining, distribution and marketing; and the import, export and conservation of petroleum, products and liquefied natural gas. It has been regulating the allocation and pricing of gas produced by ONGC and OIL through administrative orders while the gas from JVs and NELP is governed by Production Sharing Contracts (PSC). A total of 14 Public Service Undertakings (PSU) such as GAIL, and ONGC, depend on the ministry as well as entities such as the Petroleum Planning and Analysis Cell (PPAC) and the Directorate General for Hydrocarbons.
- The Directorate General for Hydrocarbons (DGH) was established in 1993 and can be considered as the upstream regulator. It has responsibilities of promoting the NELP and new exploration programmes, and managing the PSCs.
- The Petroleum and Natural Gas Regulatory Board (PNGRB) was created in 2006 to oversee the downstream part of the market. The members of the Board are nominated by the government. The Board is independent from the Ministry, but GoI can occasionally give the Board directions in the interest of sovereignty and to maintain or increase supplies. Its mission involves protecting the interests of consumers, but also registering and authorising companies active in LNG, storage, city distribution and transport. It also regulates transportation access and rates, and access to distribution or city networks. The role of PNGRB in giving licenses for city gas distribution has been challenged by the Delhi High Court in 2010, but the notification of Section 16 of the PNGRB Act by the government in July 2010 empowered the downstream oil regulator to issue authorisations for CGD licences.

1.3 Upstream Sector

The upstream sector is still dominated by ONGC and, to a lesser extent, OIL, but private companies are becoming increasingly present in this sector, notably RIL. By contrast, major IOCs remain almost absent from the Indian upstream sector, largely due to government policy on prices. The pre-NELP attempts to liberalise this sector were partially successful: the JVs created with private companies before the government launched its New Energy Licensing Policy (NELP) are largely dominated by ONGC and OIL, while the NELP attracted both private and foreign companies, notably private Indian companies such as RIL. There are also a few foreign companies such as Cairn, or BG – the exception among IOCs through its presence in the Tapi field and since 2011, BP following its partnership with RIL. Finally, NELP also attracted state-government-owned companies, such as Gujarat State Petroleum Company (GSPC).

In terms of production, most of the gas produced was coming from ONGC and OIL until 2009. The same also applied to license ownership and number of fields operated by the state-owned companies. As of 1 April 2010, there were 145 gas fields in operation countrywide, of which 131 were owned by ONGC, 3 by OIL and 11 fields by private JVs (MoPNG, 2011). This represents a very substantial increase from the year before with only 4 fields operated by private JVs.[1] The number of oil and gas fields (242) also shows the dominance of ONGC (218 fields). This changed when RIL's KG-D6 started in 2009, as the field produced 14.4 bcm during FY 2009/10. The situation regarding the operatorship of fields is not likely to change massively in the future as ONGC won half of the awarded licenses during the 8th round of NELP. ONGC produced 48.5% of Indian gas production in FY 2010/11 (ONGC, 2011).

GoI plays an important role in the allocation and pricing of gas. Historically, gas has been allocated in priority to end-users such as fertiliser producers and power plants. In 2007, the GoI started working on a new Gas Utilisation Policy. This was mostly a consequence of the dispute between the Ambani brothers on the allocation and pricing of KG-D6 gas. This and the large gap between demand and available supplies prompted the government to develop a Gas Utilisation Policy and to go back to administrative control over prices and volumes to be allocated to the different end-user sectors.

In 2008, the Gas Utilisation Policy was introduced, taking away gas producers' rights to sell the gas they discover on the open market. These guidelines would be applicable for the next five years and be reviewed afterwards. The Supreme Court reaffirmed the role of the government in the allocation and pricing of gas in 2010, following the dispute of KG-D6 gas.

Gas volumes are therefore allocated according to sectoral priorities decided by GoI. This does not force customers to take the gas; if they decline, the next on the list becomes eligible. Existing users have priority over Greenfield users. The gas is allocated as follows:

For existing customers:

- Fertiliser producers
- LPG and petrochemicals
- Power plants
- City Gas Distribution (CGD)
- Refineries
- Others.

For Greenfield users, the priorities are:

- Fertiliser producers
- Petrochemicals
- CGD
- Refineries
- Power plants.

[1] OIL operates in Assam and Rajasthan States, whereas ONGC operates in the Western offshore fields and in other states.

The above lists clearly show the preference for fertiliser producers, petrochemicals and power plants as first category customers. CGD usually comes after. GoI gave priority to power generators and fertiliser producers, making them the major customers supplied at the lowest rate (APM prices decided by the government) by the state-owned producers, but the ranking for Greenfield users is less advantageous for power plants. Industrial users rank the lowest, so that they have to find alternative sources of gas (private companies or LNG importers). When the alternative is oil or oil products, gas may still be more economical.

1.4 LNG

There are currently two LNG terminals in India, and two under construction. The first LNG terminal Dahej is owned by Petronet LNG, in which ONGC, GAIL, IOCL, Bahrat Petroleum (BPCL), GDF Suez, and the Asian Development Bank (ADB), are present. Petronet has another terminal under construction. The other LNG terminal (Hazira) is owned by two foreign companies – Shell and Total. Other players, including power companies and banks, are planning to enter the LNG scene through new LNG terminals projects, but not all of the planned terminals will actually move forward. Access to LNG terminals is not regulated currently.

1.5 Transport

There are three main transportation companies as of early 2012, the former public sector monopoly, GAIL, a new entrant, Reliance Gas Transportation Infrastructure Ltd (RGTIL) owned by RIL, and Gujarat State Petronet Ltd (GSPL), part of GSPC, a more regional player. GAIL is still the incumbent with about ¾ of the transmission network, GSPC has 1 874 km and RGTIL 1 400 km. All companies are expanding their pipeline networks.

Changes in this sector are relatively recent, as GAIL's monopoly ended only in December 2006. GoI took this decision in order encourage the construction of more transmission pipelines in the country. While transmission pipelines were traditionally linking production centres and LNG import terminals to the primary consumption centres, all located in the North West.

As of early 2012, GAIL's incumbent position is challenged as there is competition between the different companies to enhance the transmission network. GAIL's network has a transmission capacity of about 175 Mcm/d, located mostly in the North West of India. GAIL has plans to expand its network to 14 000 km and reach a capacity of 300 Mcm/d with pipelines such as the 2 000 km Jagdishpur Haldia, the 1 400 km from Bangalore to Dabhol and the 860 km from Bangalore to Kochi. These last two pipelines link the LNG terminals under construction to major cities. GAIL is also developing the network in the North, enhancing the capacity of the Dahej-Vijaipur and Vijaipur-Dabri pipeline and building to Dabri-Bawana-Nangal pipeline and the Chainsa-Jhajjar-Hissar pipeline to supply regions in the North such as Punjab and Haryana.

The second player, RIL, completed its 1 400 km EWPL in 2008, connecting Kakinada in Andhra Pradesh to Baruch in Gujarat. It connects with GAIL's HVJ line and Dahej-Vijaipur pipeline network at Ankot in Gujarat, Dahej-Uran and Dabhol-Panvel pipeline network at Mashkal in Maharashtra. What RIL has achieved in the transmission sector in such a short time frame (two years) is absolutely remarkable and their fast construction is a stark contrast with the slow progress of GAIL projects over two decades. In 2007, GAIL and RIL signed a gas transmission agreement (GTA) to share each other's pipelines for transmission of supplies from the KG basin fields. This included the transportation of gas from the KG basin through GAIL's network, and for booking of capacity by GAIL in RGTIL's EWPL. The start of KG-D6 off the east coast and new LNG terminals provide opportunities to supply new cities, in the South – Chennai, Bangalore, Tuticorin – but also in the North East. RIL and GAIL are gearing up to start the second phase of construction of pipelines to transport gas from the Krishna-Godavari Basin to the southern parts of the country. RIL was authorised to build the 600 km long Kakinanda-Chennai pipeline, the 1 140 km Kakinada-Basudebpur-Howrah pipeline as well as the Chennai-Bangalore-Mangalore pipeline and the Chennai-Tuticorin – all of them also expected by 2012.

Meanwhile GSPL, which is a pure transmission company, operates a grid of 1 874 km with a capacity of 35 Mcm/d as of 2011 (compared to 486 km in 2006) and transports gas for 31 customers including refineries, steel plants, fertiliser producers, power generators. GSPL operates on open access basis. So far, most of the network was located in the State of Gujarat, but this is changing fast as the company plans to increase the pipeline network by 1 102 km by 2013 (GSPL, 2011). Letters of authorisation have been awarded to the GSPL-led consortium following expressions of interest to PNGRB: the 1 670 km Mehsana-Bhatinda pipeline, the 740 km Bhatinda-Jammu-Srinagar pipeline, and the 1 585 km Mallavaram-Bhilwara pipeline.

Historically, transport prices were fixed by the Empowered Group of Ministers (EoGM). The APM mechanism for oil was formally phased out in 2002, but most of the gas produced by ONGC and OIL and distributed by GAIL continues to be sold at APM prices. In the transmission sector, GoI wished to develop a policy concerning the approval of pipeline construction that would be consistent, market-friendly, and would help avoid duplication of gas transport routes. In 2006, the regulator PNGRB was created to set up the bases for a competitive market and has been developing regulations since then.

The issue is that PNGRB was for a few years left without real powers, a fact that became clear with the judgement of the Delhi High Court in 2010 stating that PNGRB did not have the authority to grant licenses for laying CDG networks. Indeed, the Section 16 stating that no entity can lay, build, operate pipelines or city gas networks or expand their network without the permission of PNGRB had not been notified. MoPNG, which had been in conflict with the Board on several issues including PNGRB trying to bring LNG terminals under its jurisdiction, even proposed to set up a National Gas Highway Development Authority (NGHDA) to fast track the gas grid. This parallel authority would have undercut PNGRB's powers. The new authority would have had been responsible to authorise trunk pipelines, leaving the Board with responsibilities on product pipelines. In 2010, the Section 16 was finally notified, giving powers to the Board. In May 2011, the Supreme Court allowed PNGRB to process all pending applications regarding CDG.

In December 2006, the monopoly on transmission networks for GAIL was abolished enabling other companies to build and operate networks. The regulator PNGRB set up the system to grant authorisation for common/contract carriers pipeline and CDG networks but also the Access Code requiring third-party access for one third of the capacity and setting the tariffs of transportation for third parties. PNGRB has therefore to determine tariffs for existing pipelines as well as for pipelines authorised by the government (before PNGRB was created). This requires entities to submit their financial costs to the PNGRB. The Board has adopted a zonal tariff model under which transportation tariff remains uniform in a zone of

300 km; the tariff increases every time gas crosses to another zone. This method has been adopted to ensure maximum utilisation. This has been nevertheless criticised on the ground that it is providing expensive gas to the customers far away from the import or production source and create regional imbalances, while a postal tariff would be more appropriate by providing to all cities the opportunity to have gas delivered at the same cost.

1.6 Retail

GAIL has also a dominant position on the retail side, while OIL markets the gas it produces itself for historical and geographic reasons. The gas produced by ONGC in the western offshore fields and in other states and a part of gas produced by the JVs is marketed by GAIL. The gas produced by Cairn Energy and GSPC is sold directly by them. Some regional companies serving limited areas have also developed over the past two decades, but in most cases, are in joint ventures with GAIL, regional governments and other companies: Indraprastha Gas Ltd (IGL) (Delhi), Mahanagar Gas (Mumbai) and Gujarat Gas Company Ltd (GGCL) (Gujarat), who all distribute piped gas and CNG. IGL was set up in 1998 as a JV of GAIL, BPCL and the government of Delhi in order to improve air quality. Mahanagar Gas is a JV of GAIL, BG and the government of Maharashtra. Only GGCL is privately owned with BG owning 65% of the share, and financial institutions and public the balance.

The scarcity of supply compared to potential demand and lack of sufficient infrastructure have hampered the development of CGD and prevented new players from entering the retail market. Currently, several companies including GAIL, Adani group, GSPC and RIL are trying to obtain CGD licenses and gain market shares in the retail sector by winning licenses proposed by PNGRB. The factors that will determine the development of city gas distribution in the future are a clear regulatory framework both for the entity responsible for the promotion of city gas distribution and regulation of existing players, and for the layout of transmission pipelines across the country, cleaner cities policy, sufficient gas supply and a pricing and price reform for substitute fuels.

The first bidding round in March 2009 attracted eight companies for six cities. GAIL won the rights for five of these cities (one through a JV) and DSM Infratech the last one. GAIL has started implementing the projects. The second round in June 2009 included seven cities.

As of early 2010, only 41 cities had distribution gas networks for domestic use according to PNGRB (PNGRB, 2010), but PNGRB plans to extend the coverage to 250 cities within the next ten years supported by a cross-national network. Several issues explain the lack of development. First, the regulatory framework is unclear and not conducive to attracting private investment. City gas has a low priority according to the government's allocation policy but winners of the bids have nevertheless to secure gas supplies. Furthermore, in order for a city to receive gas, it must be connected to the main transmission system, which is still inadequate as it consists mainly in pipelines in the northwest region and the EWPL. There are therefore large transportation pipeline requirements for major cities in the South, the North and the East to be connected. Finally, a regulatory issue appeared in February 2010, when the Delhi High Court ruled that PNGRB did not have the authority to issue city gas licences. Indeed, IGL claimed it had been authorised to distribute gas in Ghaziabad (a city from the second round) by the government and challenged PNGRB's authority to issue licences in the Delhi High Court. It also claimed to have already been working in the city since 2002. In January 2010, the Court ruled that PNGRB had no powers to issue CGD licenses. Afterwards, GoI was in charge of issuing CGD licenses: it authorised winners of the first round of auction conducted by PNGRB, and confirmed IGL's right to develop the distribution network in Ghaziabad. In July 2010, the government finally notified the Section 16, empowering the downstream regulator to issue CGD licences.

2. Pricing

There are currently two different pricing regimes in India, which makes the system relatively complex. One is the gas pricing under the Administrative Pricing Mechanism (APM) regime and the other the non-APM regime; this had led to the creation of two distinctive markets. The APM price is fixed by the government. As far as non-APM gas is concerned, there are two sources: the gas produced by JVs, which is governed by the Production Sharing Contracts (PSCs) provisions and the LNG imported, either under long-term contracts or as spot LNG. A key issue for the stability of this dual system was the declining availability of APM gas while non-APM gas was increasing. In 2007/08, APM gas sold by public sector companies accounted for 60% of the domestic market, but only 55% for the following year. It was estimated to be down to 35% as of early 2010.

Reforms, which had been delayed for quite a long time, finally took place in May 2010. The government decided to increase APM prices to USD 4.2/MBtu and give freedom to ONGC and OIL to market gas produced from new fields at non-APM prices.

2.1 Gas prices before the reform

The government has always had a key role in deciding gas prices for the historical reasons discussed in the first part of this Working Paper.

- From 1959 to 1987, gas prices were fixed by the PSUs ONGC and OIL.
- In 1987, the Empowered Group of Ministers (EGoM) was put in charge of determining gas prices. Over 1987-2002, three committees were successively in charge of the three five-year periods. Typically, gas price included a producer price and a transport tariff. On top of this, a contribution to the Gas Pool Account (created in 1992) was set up, to compensate companies involved in E&P, marketing and transport of gas for their low margins in the development and sales of gas.2 Initially the producer prices reflected long-term production costs and increased in 1992 from INR 1 400/1 000m3 (USD 0.78/MBtu) to INR 1 500/1 000m3 (USD 0.84/MBtu).3 In 1997, GoI decided to put gas prices at landing point at parity with a basket of LS/HS fuel oil prices with the view to achieve full parity by 2001-02. A floor (INR 2150/1 000m3) and a ceiling (INR 2 850/1 000m3) were also introduced. As oil prices increased in the early 2000s, the project of full parity was abandoned and prices stayed at the ceiling level. By 2005, they were at 34% of fuel oil prices.

  Transport prices were also fixed by the EGoM. Typically transport along the HBJ increased over the period from INR 850/1 000m^3 to INR 1 150/1 000m^3. Furthermore,

[2] In particular, the sums on this account were used to compensate OIL for subsidized gas prices in the North East, compensate PSUs for increases in operating costs, payment of higher prices for the new JV and exploration and development of small fields.

[3] All prices are based on gas with a calorific value of 10,000 kcal/m^3.

margins charged by marketers such as GAIL were also decided by the government. These marketing margins differed depending on the origin of the gas (LNG, domestic gas field).

Issues had already been arising with respect to different costs of production between the companies, the likelihood of importing more expensive gas in the future and increasing international oil and gas prices over 2000-05. On the transport side, issues included no distance-related charges for existing pipelines such as HBJ and different end-user taxes. In 2002, the APM system was formally abolished for oil but APM prices remained for gas produced by PSUs.

- In 2005, the price of APM gas of ONGC and OIL was revised. Based on recommendations of the Tariff Commission, the Cabinet Committee on Economic Affairs decided that APM gas prices would be increased. All available APM gas would be dedicated to power generators, fertilisers as well as specific end users covered by Court orders and small-scale consumers having allocations up to 0.05 Mcm/d. At that time, ONGC and OIL produced about 55 Mcm/d APM gas from nominated fields. In July 2005, the price of APM gas was increased from INR 2 850/1 000m3 (USD 1.59/MBtu) to INR 3 200/1 000m3 (USD 1.79/MBtu) except in the northeast region where gas was sold at 60% of the revised price, i.e. INR 1 920/1 000m3 (USD 1.07/MBtu). In 2007, the Tariff Commission proposed to increase ONGC's price to INR 3 600/1 000m3 (USD 2.01/MBtu) and OIL's price to INR 4 040/1 000m3 (USD 2.26/MBtu), but this increase did not happen.

  - APM gas prices for the transport sector (CNG), small industries and consumers would be progressively increased from INR 3 200/1 000m3 (USD 1.79/MBtu) over the following years to reflect the market price. As they became the second category after fertilisers and power producers, small users/CNG saw prices increasing from INR 3 200/1 000m3 (USD 1.79/MBtu) to INR 3 840/1 000m3 (USD 2.15/MBtu) in 2006 (INR 2 304/1 000m3 in the North East).
  - Meanwhile, non-APM gas was sold to consumers at the price at which GAIL bought from producers at landfall point. In this case, it depended whether gas was produced under PSC predating NELP, NELP gas or LNG.
  - Part of the gas sold under PSCs dated from pre-NELP, notably the gas from Panna Mukta Tapti (PMT) and Raava. Their price was linked to the 12 months average of fuel oil prices. For PMT, the ceiling was progressively increased over the years from USD 3.11/MBtu initially to USD 3.86/MBtu in 2005 and USD 4.75/MBtu in April 2006. Raava gas prices were increased to USD 3.5/MBtu in 2006.
  - Gas sold under PSCs from the NELP has a different regime. The PSC contractor is required to sell the gas at a competitive arms-length price to the benefit of both parties (the government and the contractor), and the price formula has to be approved by the government. Indeed the company has to support the entire investment, honour the minimum work programme of committed exploration, and pay a penalty in the event of their failure. According to the PSC, the company recovers the investment during the first years, while the government's share of petroleum profits is the lowest. The government's share increases with cost recovery. Therefore, the valuation of the gas produced from the NELP fields is very important for the government revenues. The price level that RIL received for the KG-D6 gas for the first five years of production (until 2014) is USD 4.21/MBtu.

2.2 The 2010 reform

As mentioned earlier, the reform became urgent as non-APM gas saw a dramatic increase in volume and share in 2009.[4] This represented an opportunity for GoI, especially with a single source (KG-D6) expected to represent half of the production by 2012. Furthermore, APM gas has been allocated in priority to power producers and fertilisers, two sectors expected to see their demand increasing over the coming decade (see section on demand). Meanwhile, keeping artificially low prices is difficult on a long term when production is required to increase at the same time. This tends to discourage upstream investments, and companies have difficulties to cover production costs and the recovery of capital. However, this reform was met with strong resistance from the Ministry of Power and Ministry of Chemicals and Fertilisers. The subsidies to fertilisers had already multiplied by four between 2004/05 and 2008/09 to reach INR 76 603 crore (USD 15 billion) in 2008/09, dropping back in 2009/10 to INR 52 980 crore (USD 12 billions).

Gas availability and affordability for customers are crucial for gas development in India. Demand for gas is infinite at USD 2-3/MBtu but more limited at USD 7-8/MBtu for Indian main gas users – fertiliser producers and power generators. Naphta competes against gas for fertiliser producers and coal against gas for power generation. The issue on competitiveness of gas under different gas prices will be looked at in more details in the demand section.

In May 2010, the MoPNG decided to increase APM gas prices from USD 1.79/MBtu to USD 4.2/MBtu, a level similar to KG-D6 gas. The price is on a NCV basis at 10 000 kcal per standard cubic meter, to be fixed in USD and converted in rupees based on the exchange rate of the previous month and exclude cess, any transportation charges, marketing margins or taxes. A marketing margin of INR 200/1 000m3 (USD 0.112/MBtu) would be payable by the customers to the company marketing the gas produced by the NOCs (often GAIL). Users in the North East get a 40% discount and pay only USD 2.52/MBtu, with the government paying the difference to PSUs on its budget. MoPNG also allowed ONGC and OIL to market gas produced by them at market rates. For example, ONGC was given permission to sell gas from its C-series fields in Mumbai offshore at USD 5.25/MBtu, even higher than KG-D6. These fields are expected to produce 1 bcm/y.

2.3 Importing LNG is no longer cheap

India is becoming a relatively significant importer of LNG, so far its only source of imports. LNG is sourced both from long-term contracts and on a spot based.

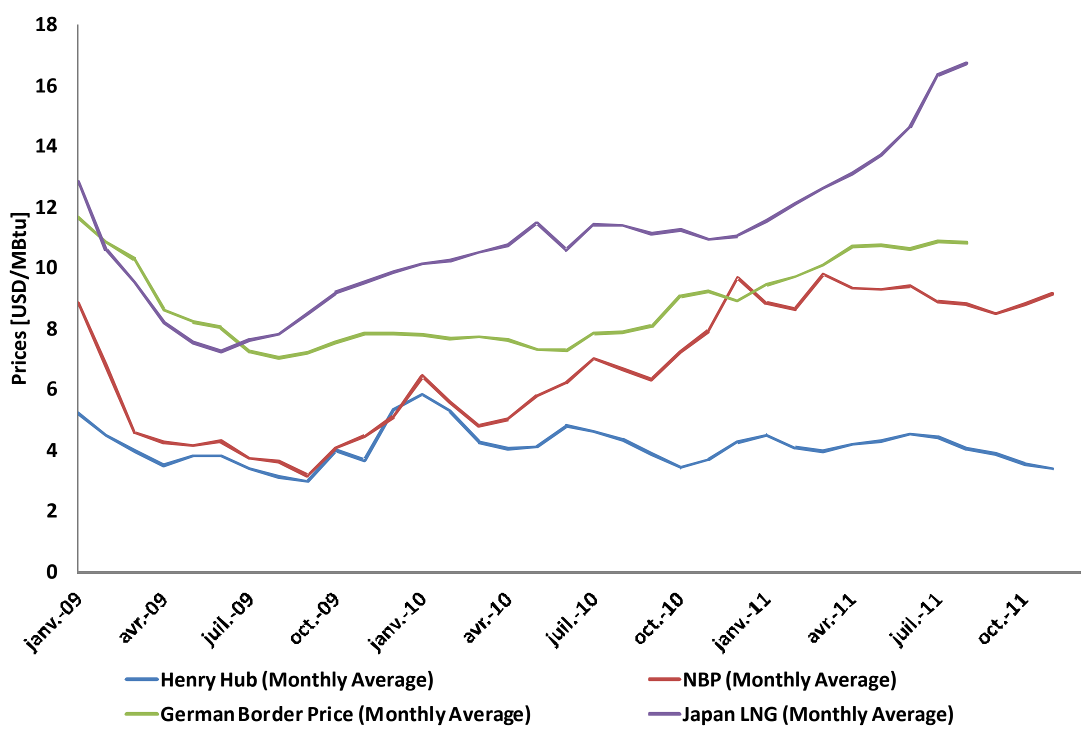
- Long-term contract with Qatar's RasGas (Dahej). The pricing formula proposes a fixed price indexed to a JCC price of USD 20/bbl for the first five years until December 2008 (USD 2.53/MBtu); afterwards, the price would be linked to the previous 12-month JCC prices, with a floor and a cap based on the average JCC prices during the previous 60

[4] The pricing issue is not limited to gas: most refined product prices are kept low in India in order to insulate consumers from high international oil prices. On 25 June 2010, the EGoM decided to let oil marketing companies set the price of some oil products, while they used to be determined by GoI. Petrol prices increased. LPG and kerosene have been and will continue to be subsidised for domestic users. The government used to partly reimburse the state-owned oil marketing companies for under-recoveries, by using "oil-bonds" which amounted to USD 20 billion in 2008/09. This has a significant fiscal impact.

months. Given the evolution of oil prices, there is no doubt that these LNG prices have increased and are much less advantageous than during the initial period.

- Short-term contracts: Petronet negotiated with RasGas until December 2008 for 1.5 mtpa, Petronet paid USD 8.50/MBtu, but the price for end-consumers was pooled with the gas Petronet bought under the long-term contract.
- Spot cargoes: while Indian companies could enjoy low gas prices in 2009 due to the gas glut, the situation has changed since then and international gas prices increased substantially in 2010 and 2011 following the tightening of gas markets. Only Henry Hub gas prices remain very low. Petronet mentioned prices around USD 14/Mbtu end 2011, versus prices of USD 16-17 three or four months before.
- Petronet's terminal in Kochi to be commissioned by 2012 has contracted to receive LNG from Exxon Mobil's 25% stake in Australia's Gorgon project in all likelihood at much higher prices than existing LNG contracts. LNG supplies will start in 2014-15.

Figure 1: International gas price evolution



Source: German Ministry of Economics, Japanese customs, ICE.

2.4 Which way forward?

India faces a challenge which is not unique: rapidly increasing costs of imports versus much cheaper costs for domestically produced gas with a price sensitive market. Countries such as China, some Latin American or Middle Eastern countries and even OECD countries also face similar challenges. The answer to these challenges is often to increase prices, or face shortages which could then affect directly or indirectly the economic growth (through power shortages or lack of gas as a primary fuel). It is very sensitive decision to increase prices, and the 2010 reform was certainly a big step forward. The disparity between APM and non-

APM prices has certainly been reduced, but with the recent evolution of international gas prices, the gap between domestic gas and LNG import prices (notably spot) has gone even wider (see table 1).

Now the question is whether additional steps are needed and where. There is no doubt that domestic production will and needs to play a fundamental role in Indian gas supplies. The new future pricing mechanism needs to incentivise gas production, conventional but also shale gas, deep-water gas and CBM. Additionally, India will increasingly depend on imports. In the medium term, this will be LNG, which – as mentioned before – will not be cheap. In the future, there are likely to be imports by pipeline. Current practices of the exporting countries considered – Iran and Turkmenistan – suggest that gas prices are likely to be oil linked, but the actual level is very much uncertain and depends also on transit costs.

Table 1: Gas price differentiation on the Indian gas market (end 2011)

Gas source	Import or production price
OIL	USD 4.2/MBtu (APM regime)
ONGC	USD 4.2/MBtu (APM regime)
LNG long-term contract	USD 7-9/MBtu (estimates)
RIL	USD 4.215/MBtu
C Fields	USD 5.25/MBtu
Panna Mukta Tapti field	USD 5.57-5.73/MBtu
LNG spot	USD 14-17/MBtu

Note: The end-user delivery price would include a transportation price.
Source: Indian Oil and Gas, Industry announcements and presentations.

On the production side; there are still wide disparities between the different prices for domestic fields. The idea of pooling has been investigated many times (and usually includes imports), but there could be some challenges to move towards that direction. Indeed, gas users, which had been allocated cheaper gas than the new reference price, will be adversely affected and would certainly be opposed to such changes. The Planning Commission of the GoI in its report in August 2011 (Planning Commission, 2011) did not recommend any pooling for natural gas on overall level, nor on a sectoral basis. The Committee opted for a preferential allotment of domestic gas to specific key users, namely the power sector and fertiliser producers. There should be also some quantities reserved for CGD and other Court mandated customers. The other non priority users would operate with prices on a market basis. The Committee hoped that “large users may opt to choose to source their own R-LNG and this will help develop a competitive market for R-LNG”, although this may very much depend on the international market conditions.

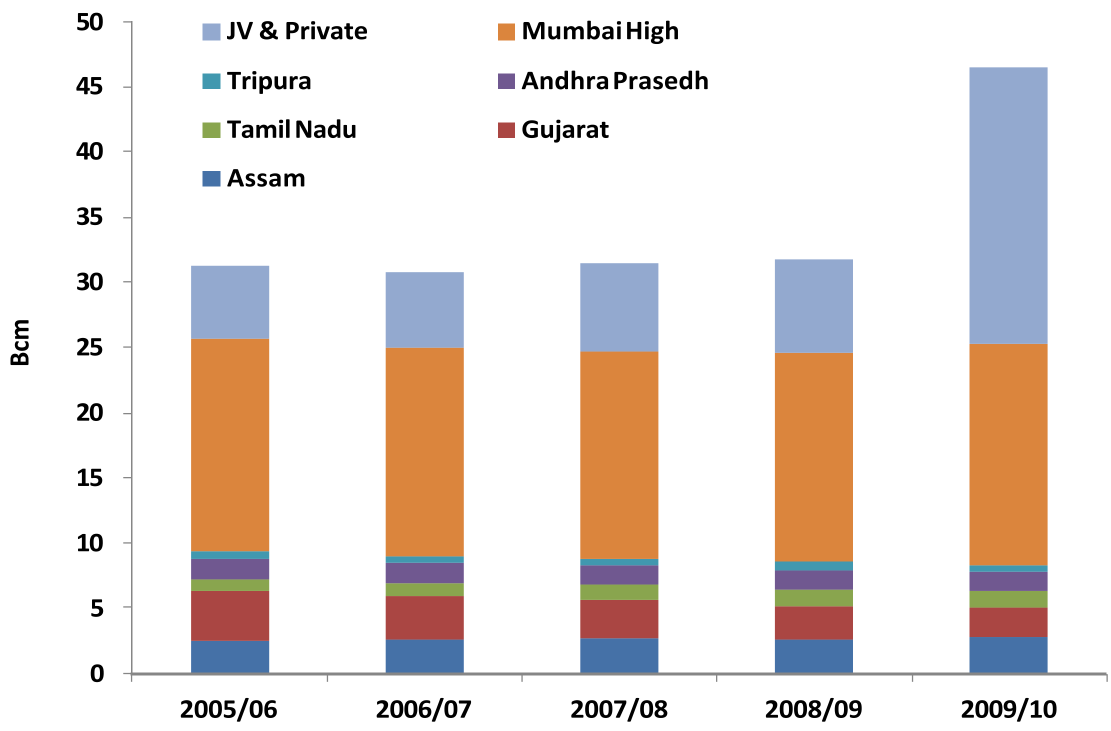
India may not be yet at the stage where it could explore the full deregulation of domestic gas prices like the United States or some European countries did before; but this may be a way to explore. This may not close the gap between domestic and imported gas prices though, and again the idea of pooling may be explored. The other part of the pricing issue that is less explored is how final end-user prices are set up, and to what extent the new regulator, PNGRB, should play a role in this issue. As mentioned before, transport tariffs depend on the distance, potentially disadvantaging the remote regions while different taxes are applied depending on the region.

3. Domestic production

3.1 Historical trends

As of 1 April 2010, proven natural gas reserves in India were 1 437 bcm, a substantial increase from the previous level of April 2009 (1074 bcm). There is a complete reversal in the relative share of onshore versus offshore. Onshore reserves surged from 287 bcm to 829 bcm, while offshore reserves slightly dropped from 787 bcm to 608 bcm according to the Ministry of Petroleum and Natural Gas.[5] Exploration Domestic production was at 12 bcm in 1990, has been almost flat at 30-32 bcm since 2002, before increasing to around 52 bcm during 2010/11, much higher than the previous levels.[6]

Figure 2: Domestic net gas production by region (2005-10)



Source: Ministry of Petroleum and Natural Gas of India.

The share of offshore production increased to 82% in 2009/10 and again to an estimated 84% in 2010/11, reflecting new sources of gas coming from the Krishna Godavari basin. Fields which are located in Gujarat, Assam and Andhra Pradesh are the major sources of onshore gas, while smaller quantities of gas come from Tamil Nadu, Tripura and Rajasthan.

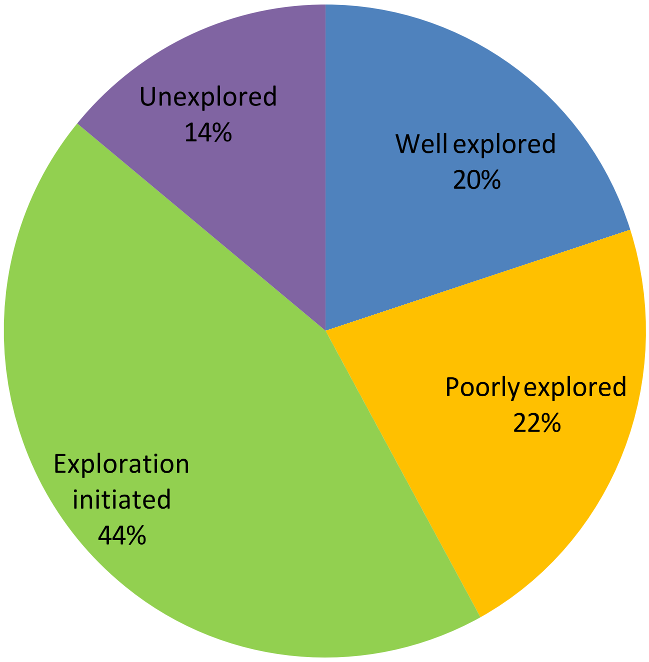
[5] This compares with 1 450 bcm reported by BP at the end of 2010, versus total proven gas reserves are estimated at 187 tcm (BP).

[6] IEA statistics. Statistics may slightly differ from the Ministry's data due to use of different calorific values or inclusion of gas flared.

The fiscal year 2009/10[7] saw the drilling of 144 exploratory wells and 284 development wells working with total metreage of 1 019 000 m, the highest levels in last five years.

Despite a relatively long E&P history, one major issue concerns the fact that no full geological survey of the sedimentary basins has been completed (see Figure 3). This issue, which is recognised by the government, is nevertheless critical to attract investors.

Figure 3: Level of exploration



Source: Opportunities in oil and gas markets, R S Sharma, Chairman of ONGC, September 2009.

While ONGC has been the dominant gas producing company, the situation has been changing with RIL starting producing. The share of JVs and private companies in total gas production doubled from 2008/09 to 2009/10 to 45%; although the increase will slow down in the following years, these companies seem now set to play a significant role on the upstream market. But incumbents' production is also likely to increase further. Indeed, natural gas produced from existing fields in nominated blocks of ONGC and OIL was historically treated as Administered Pricing Mechanism (APM) gas. However, following the decision on prices in 2010, both ONGC and OIL will be allowed to sell any production from new fields in their blocks at market prices that are set and approved by the government to encourage the two companies to invest in upstream development (see previous section on pricing). Meanwhile JV gas from allocated fields before NELP is sold at "market prices", again set and approved by the government.

The start of Krishna Godavari KG-D6 (block DWN-98/3) field operated by Reliance Industries Ltd. (RIL) changed the upstream picture. The field is located in the Bay of Bengal off the

[7] In India, many data are given for the fiscal year, a period starting on 1 April and finishing on 31 March. The Petroleum Planning & Analysis Cell (PPAC) and the Ministry also provide calendar year data on their website and in their annual reports.

eastern coast of India. It produced 14 bcm in FY 2009/10, and an estimated 20 bcm in FY 2010/11 (720 bcf according to RIL) or one third of total gas consumption in India that year. The gas from KG-D6 was supplied to 57 customers such as fertiliser producers, power companies – the two main sectors, but also steel, petrochemicals and refineries. RIL is currently working on an integrated development plan for all gas discoveries in KG-D6, including existing wells and other discoveries within the block in order to compensate for the field's recent issues with production levels. There are disagreements on the reasons behind the decline – RIL mentions the complexity of the field, while MoPNG said that DGH mentioned wells drilled but not put on production as planned. Initial estimates quote over 20% of production decline compared to the previous year for April-December 2011. It is not the objective of the paper to decide on who is right or wrong.

3.2 The New Exploration Licensing Policy

The evolution of Indian gas production over the past two years results from the New Exploration Licensing Policy. Although there were exploration bidding rounds organised over 1979-98 allowing private companies to bid – four during 1979-91 and five during 1994-95, they were not very successful. Only 148 bids were made for the 349 blocks offered and only 28 contracts were signed. Additionally, there were delays before getting the approval from the relevant agencies, retail price caps were hindering investment in new gas production and supply infrastructure, while private and foreign oil and gas companies had little access to the Indian market. By the end of the 1990s, as much as half of India's gas demand was unmet (MoPNG, 2000).

This prompted GoI to adopt in 1997 the New Exploration Licensing Policy (NELP), aiming at creating a more investor-friendly framework. In particular, NELP included a deregulation of the upstream sector, opened the upstream to private and foreign companies with the right to sell produced gas at market price (although the government would have a say on pricing) and a gradual evolution to full market pricing. The NELP introduced attractive measure such as no limitation on the number of oil and gas exploration blocks, the guarantee of attractive tax rules (such as a seven-year tax holiday from start of production or no customs duty on imports for petroleum products). Unlike some other countries, there was no carried interest by PSU (India's National Oil Companies [NOCs]) or what was previously the case: the option (but not a requirement) for PSUs to take participation up to 40%. Conditions for deepwater projects were made more attractive by being charged lower royalties than other projects.

However, the government decided in 2007 to restrain the market liberalisation trend with its gas utilisation policy (see section on policy and regulation). Furthermore, in early 2008 the Indian Finance Ministry issued a decision to scrap the seven-year tax holiday from payment of income tax on profits earned from production and sale of NELP natural gas output in the 2008/09 budget. Early 2009, this decision was cancelled by the Finance Minister for the 2009/10 budget for the last NELP round in order not to deter investments.

The recent NELP VIII and IX in 2009 and 2011 show a limited success: during NELP VIII, there were only 76 bids for 36 out of 70 blocks, leaving half of the blocks unwanted. During NELP IX, there were 74 bids for 33 blocks offered. Once again, the last two rounds have shown the dominance of the incumbent player ONGC. In NELP VIII, ONGC made 25 of the

36 bids and won 17 (14 as the operator), many of them in partnership with other companies.[8] BHP Billiton bid for three blocks. Some private players such as Cairn India, Jubilant Energy and Deep Energy were successful, but RIL was notably absent. A new Indian player, Andhra Pradesh Gas Infrastructure Corp., appeared. In NELP IX, ONGC bid for 29 blocks, OIL for two, GAIL and Bharat Petroleum for four each, RIL for six and Cairn for two. BP was the only IOC present at that round.

Table 2: Number of blocks in Pre-NELP and NELP rounds (January 2012)

NELP Round	Pre NELP	I	II	III	IV	V	VI	VII	VIII	IX
Offered	379	48	25	27	24	20	55	57	70	74
Awarded	28	24	23	23	20	20	52	41	36	
To ONGC	*	8+11**	16	13	14	8	25	19	17	
Surrended by ONGC		4	14	1	1					
ONGC as operator		5	2	11	11	3	24	18	14	

*ONGC could take shares in licenses in all the Pre NELP blocks.
**Acquired majority interest in KG 98/2.
Source: ONGC (2009), ONGC (2010), press releases (2010, 2011, 2012).

The NELP policy aiming at increasing upstream investments by creating an investor-friendly climate was relatively successful and resulted in some major discoveries while allowing India to gain experience in the deepwater area. It has attracted many Indian private companies like RIL or Andhra Pradesh Gas Infrastructure, as well as foreign companies such as BHP Billiton, BG, Cairn Energy, Gazprom, Eni, Santos, Petrogas, although these companies still have a limited role. Few major IOC has been participating in the bidding however, most likely due to the government's policy of keeping relatively low prices on the domestic market.

After eight NELP rounds between 1999 and 2009 (and one on-going), the area under exploration has increased six-fold – from 11% of the Indian Sedimentary Basin area before implementation of NELP to 68%. But only 22% is well explored. A total of 400 blocks have been offered by the government so far and 239 awarded (see Table 2), 72 of which were awarded to private companies and JVs. The number of production companies increased from 2 in 1990 to 12 in 2000 and 71 in 2009 and the number of producing basins increased from 3 in 1990 to 10 in 2009. Significant discoveries were made including Krishna Godavari in 2002 and the Cairn's discovery in Rajasthan. It also created an opening of acreages in ultra deepwater and frontiers areas.

The 9th NELP round is likely to be the last one as the DGH has indicated that it is planning a gradual phase-out of the existing NELP licensing regime in favour of a new Open Acreage Licensing System (OALP). This has been discussed for the past three years. However, there are still some issues to be tackled. This OALP system will enable bidders to bid for blocks on offer at any time of the year. Data on these blocks would be made available to the bidders through the National Data Repository (NDR), which would be in charge of collecting data on

[8] ONGC's partners in these blocks are BG, OIL, Gujarat State Petroleum Corporation Ltd. (GSPC), GAIL, NTPC, Indian Oil Corporation Ltd. (IOC), and Andhra Pradesh Gas Infrastructure Corporation (APGIC).

basins. As three quarters of basins are poorly or not explored at all, major work needs to be conducted. So far, progress on the NDR has been relatively slow.

Another crucial issue for the development of gas fields is pricing. While the increase of APM prices will incentivise PSUs to increase production levels, there are worries among investors about government decisions and interferences on pricing. This is illustrated by the battle over the allocation and price of the Krishna Godavari KG-D6 field.

3.3 The Krishna Godavari KG-D6 field

The major upstream development over the past few years is the start of the deepwater Krishna Godavari KG-D6 (block DWN-98/3) field operated by RIL. In February 2011, RIL and BP agreed on a partnership. BP takes a 30% stake in 23 oil and gas PSC operated by RIL in India, including KG-D6. RIL will benefit from BP's deep-water expertise, while remaining the operator. BP and RIL also created a 50:50 JV for the sourcing and marketing of natural gas in India.

Discovered in 2002, the field began producing in April 2009, and its potential is estimated at 337 bcm (11.9 tcf) (DGH). Initially, production was expected to increase by an additional 10 Mcm/d each month up to 40 Mcm/d by July 2009 and to reach a plateau production of 80 Mcm/d only by 2011-12 – the equivalent of 29 bcm of annual production, which would double India’s current production. It was then expected to plateau and dwindle from 2017 to 2020. However, potential production of 60 Mcm/d was reached in July 2009, although the field did not produce this amount of gas until early 2010 due to the lack of offtakers. However, since end 2010, production has been going down, creating issues regarding the allocation of gas.

KG-D6 faced two issues over its development and first year of production: the allocation and price of the gas, and the legal dispute between the Ambani brothers, Mukesh Ambani who owns Reliance Industry (RIL) and Anil Ambani who owns Reliance Natural Resources (RNRL). It ended in May 2010 with the ruling of the Supreme Court.

Gas is to be sold according to the Indian gas policy reflecting recent decisions on volumes and end-consumers. This section is slightly difficult due to the recent decline of KG-D6 production. The gas produced during Phase I (40 Mcm/d) is allocated with the following priority and volumes; despite the decline, production is still above these levels.

- Fertiliser companies: 15 Mcm/d
- Existing gas-fired power plants and plants to be commissioned before April 2010: 18 Mcm/d
- LPG and Petrochemical plants: 3 Mcm/d
- City gas distribution: 5 Mcm/d.

For Phase 1, Reliance had contracts to sell gas to 15 fertiliser manufacturers, 19 power plants and 3 steel companies. It had also signed a sale and purchase agreement with GAIL for its LPG plant and with Indraprastha Gas for city gas for 0.3 Mcm/d to be increased to 0.5 Mcm/d by March 2010 and 2.1 Mcm/d within five years. During the first months of production in 2009, RIL had been forced to cap output, as close to one-fourth of the initial allocations were not taken. Customers, such as state power utility National Thermal Power Corporation (NTPC), Gail, Essar Power, and Ratnagiri Gas and Power, were not taking their allocated quantities or are taking very irregular quantities which could threaten the field's operations. Ratnagiri was not taking the 2.7 Mcm/d for which it signed up because it had contracted to buy regasified LNG from Petronet LNG through September 2009.

Given the initial good performances from the field and that RIL was to increase output to 60 Mcm/d (22 bcm), EGoM decided on further allocations in November 2009. Another 30 Mcm/d was to be sold on an interruptible basis. The final allocation of RIL's gas is given in Table 3 as of end-2010. The dramatic increase of gas use in the power generation sector is a clear result of this (see section on demand). Fertilisers have been also switching from expensive oil products to gas. Given the latest developments of gas production, the firm allocation may be about to be met, but the customers allocated interruptible supplies are unlikely to see their demand being met.

Table 3: Allocation of KG-D6 gas

Sector	Firm allocation (Mcm/d)	Interruptible allocation (Mcm/d)
Power plants	31	12
Fertilisers	15	
LPG and petrochemical	3	
City gas	5	2
Reliance Petroleum	1.9	
Oil companies	6	6
Captive power		10

Source: Press releases (2010).

In 2004, NTPC launched a tender for gas supplies and Reliance Industries, the main owner and operator of KG-D6 at that time, offered USD 2.34/MBtu for 12 Mcm/d for 17 years. Reliance Industries was then owned by Dhirubhai Ambani, Mukesh's and Anil's father. But in 2005, following his death, the company was split into RIL and RNRL. The conditions of the split were agreed in a Memorandum of Understanding (MOU) signed in June 2005 stating in particular that RIL would supply RNRL 28 Mcm/d for 17 years at the same price than originally offered to NTPC.

In 2007, a price was agreed between RIL and the government under the PSC so that RIL was to sell gas at USD 4.2/MBtu for the first five years of production. This price level, often reported, reflects the calculation under a formula linking the price of gas to the price of oil:

$$GP = 2.5 + (OP - 25) ^{\wedge}0.15$$

where OP is the annual average Brent crude price for the previous FY, with a cap of USD 60/bbl and a floor of USD 25/bbl. Since 2007, the annual Brent price has always been above USD 60.

Following that decision, Mukesh Ambani argued that RIL should sell gas at USD 4.2/MBtu instead of USD 2.34/MBtu to RNRL as well. But Anil's RNRL refused to pay this price on the basis of the MOU. This started a legal battle between RIL and RNRL. The legal proceedings revealed some agreements, notably one allowing RIL to use 25 Mcm/d for its refinery, petrochemical plants or sales to other users at a price determined by RIL.

Meanwhile, RIL and NTPC had already been in court since 2006, first because NTPC was accusing RIL of not fulfilling its supply obligations. After the agreement on a price level of USD 4.2/MBtu for KG gas, NTPC was also complaining about RIL's refusal to provide gas at USD 2.34/MBtu. This put the two Ministries (Power and Petroleum and Natural Gas) in different positions.

In June 2009, the Bombay High Court decided that RIL should honour its engagement and supply 28 Mcm/d to RNRL at USD 2.34/MBtu. This is where the government stepped in July 2009, challenged the High Court's decision and stated that the pact between the two brothers should be null and void. Gas is national wealth and belongs to the state. The government therefore asked the Supreme Court to break the judgment of the High court. This effectively happened in May 2010.

The dispute between the two brothers could have many consequences for the Indian market.

- The position of the state during this dispute has been closely scrutinised by foreign investors. It is not so much the issue on prices – a higher price would always be welcomed by potential upstream investors – than the fact that the government is intervening in commercial arrangements. As the Supreme Court supports the position of the Petroleum Ministry that gas is national wealth, then all companies having PSC with the government could see the conditions initially agreed under the PSC changed afterwards.
- Selling gas at a lower price would have harmed RIL's revenues but also government revenues. Fields under the NELP are developed under a PSC between companies and the government. According to the PSC, it is intended that the company recovers the investment in the first years, then each party is entitled to his part of the discovered gas.
- Higher prices create uncertainties on the demand side. NTPC and RNRL as well as other power producers will have to pay a higher price than they thought. Meanwhile, customers, such as fertiliser companies, would have preferred a lower price to improve their competitiveness and also reduce the subsidies paid to the sector by the Indian government.

3.4 What is the potential of unconventional gas?

India could hold both CBM and shale gas, but due to the low exploratory levels, there are many uncertainties on this potential. In its study "Shale gas is a global phenomenon" released in 2010, the EIA estimated shale gas recoverable potential at between 1.8 tcm (63 tcf), roughly the current proven gas reserves, although some other agencies and companies have given much higher estimates 1.6 tcm (55 tcf) to 3.1 tcm (110 tcf) while Schumberger have estimates of 300 to 2 100 tcf, but for reserves in place. But India is also believed to hold CBM resources, most of which are located in the North-East and North-West of the country. As of early 2012, there is some limited CBM production, while shale gas production seems still further away.

There remain a few key issues for the development of unconventional gas: lack of data as most of India remains underexplored (and unconventional gas has very often been considered as a long-term resource), pricing (including taxes and royalties) and regulatory policy, lack of domestic infrastructure and expertise. As far as CBM is concerned, other issues are technical challenges, utilisation of the gas produced, and inferior grade of coal in India. There are also environmental challenges common to both shale gas and CBM including use of water.

Historically, India has been focusing more on CBM than shale gas. Four CBM licensing rounds have been organised so far, with the 4th in 2009 with 33 blocks offered. This last licensing round went actually better than the conventional licensing round: eight of the ten CBM blocks attracted 26 bids, notably from Essar Oil and Deep Energy. It had estimated reserves of 330 bcm for a production of around 3 bcm/y. Seven CBM blocks were awarded, including two to Australian CBM player Arrow Energy and four to Essar Oil. Arrow Energy will develop one with Oil India and the second with Tata Power; production is expected for 2014. Actually, a handful of Indian and foreign companies such ONGC, BP, RIL, Essar Oil, Arrow Energy, GAIL, and GEECL are already active. Unfortunately, CBM production, which started in 2007, is still very limited. From April to November 2011, only 39 Mcm were produced, or 0.1% of the gas produced in India during the same period. This is far from the 50 bcm produced in the United States (8% of total US production). CBM is often sold as compressed natural gas (CNG) or to power plants. DGH expects a production of 7.4 Mcm/d by 2015 (2.7 bcm), which looks very optimistic at this stage.

By contrast, shale gas production has not even started in India, but the interest is rapidly growing due to the example of the United States where production increased from 20 bcm in 2005 to around 150 bcm in 2011. Six basins could have good shale gas potential — Cambay (Gujarat), Assam-Arakan, Gondwana, Krishna-Godavari (onshore), Cauvery and the Indo-Gangetic basins. It is rapidly gaining the attention of the main industry players and of the government, but there are still uncertainties on when exploration would really start. Early 2012, the auction of shale gas blocks has been announced to be postponed from 2012 to end-2013, when the government would have its policy in place.

NGC launched a pilot project in 2011, and actually found shale gas in West Bengal. RIL has moved ahead by acquiring acreages in the US shale play Marcellus, a way to gain experience to be transferred to Indian shale gas deposits. ONGC has not concluded any partnership with experienced players or tried to acquire experience in North America so far.

<u>3.5 Outlook</u>

Indian gas production may have jumped in 2009 and 2010, but the recent developments show how challenging developing new production may be. Meanwhile, existing fields are seeing their production declining and will need to be replaced; hence the efforts to bring new supplies to the market must be continued. Additionally, there are still major challenges for natural gas production in India. The government itself recognises that “the international response to the recent NELP offers has been poor” and that “it is necessary to re-examine whether the current policy provides a sufficiently attractive framework for policy which can attract investors in this area”. Here again the issue of gas pricing is key to succeed attracting investors to this sector.

Production levels in the previous FYP were always higher than actual levels: production was anticipated to grow from 30 bcm in 2007/08 to 44 bcm in 2008/09, but fell short of that target in particular because the KG-D6 field started later than expected. Again in 2009/10 and 2010/11, production was over 15 bcm below the targets. In its document on pooling gas prices, the Committee presented several future development scenarios for gas production in

India, highlighting the uncertainties over this key component of gas supplies. The less optimistic scenario gives production increasing by 6 Mcm/d per year and the most optimistic by 16 Mcm/d per year, resulting in a production level of 69 bcm (189 Mcm/d) in 2016/17 to 87 bcm for the most optimistic. This document also gives the projected availability of gas according to EGoM on July 28th, 2010 (see Table 4). Firm supplies would increase to 68 bcm by 2015/16, while all supplies would jump to 73.6 bcm. This scenario is in the range of previous scenarios, and the Committee seems to be more comfortable with production levels at around these levels. Given the recent developments, this appears as a reasonable approach.

The IEA also foresees a substantial increase between 2008 and 2015 based on the current upstream developments with domestic production reaching 67 bcm by 2015, and then continuing to increase up to 135 bcm by 2035 in the Golden Age of Gas Scenario.

Table 4 projected availability of gas according to EGoM on July 28th 2010-15 (Mcm/d)

Source	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
Small size	2.03	1.78	2.44	2.05	20.3	1.65
Medium size	14.31	11.62	9.55	8.21	7.29	6.85
Pre-NELP	2.11	1.83	1.39	1.19	1.15	1.115
NELP	59.6	60.29	90.95	95.02	98.7	106.68
ONGC nominated firm	58.86	68.74	73.1	67.57	61.34	55.77
ONGC (additional indicated)				7.53	13.21	15.23
OIL	5.8	5.8	5.8	5.8	5.8	5.8
CBM	0.1	0.41	3.37	5.8	7.3	8.59
All except ONGC add.	**142.8**	**150.5**	**186.6**	**185.6**	**183.7**	**186.5**
All	**142.8**	**150.5**	**186.6**	**193.2**	**196.9**	**201.7**
All except ONGC add. (bcm)	**52.1**	**54.9**	**68.1**	**67.7**	**67.1**	**68.1**
All (bcm)	**52.1**	**54.9**	**68.1**	**69.5**	**71.9**	**73.6**

Source: GoI, Report of the Inter-Ministerial Committee on Policy for Pooling of Natural Gas prices and Pool Operating Guidelines, August 2011.

The main issues faced by Indian upstream are the declining production from mature fields, low level of exploration, delays between discovery and production, gas flaring, lack of deepwater drilling. Production from existing field is declining, despite attempts to smooth the decline. ONGC has introduced Improved Oil Recovery and Enhanced Oil Recovery (IOR/EOR) schemes to address this issue and improve the oil and gas fields' production rates. The company applied these techniques to 15 major fields. There is also significant work to be conducted in terms of exploration. This is why the Directorate General of Hydrocarbons (DGH) wants to create the National Data Repository (NDR) in order to gather E&P data. Additionally, gas flared has been hovering at around 1 bcm of gas flared, accounting for 2%-3% of total gas production. This is a considerable improvement from the one third of gas production (around 5 bcm) flared in the early 1990s. The percentage of gas flared to gross production from particular fields varied between 0.06% in Andhra Pradesh up to 8.2% in the Assam fields. It goes up to around 80% for CBM fields. Flaring remains an important problem to be solved for a country facing gas scarcity.

Despite the shortcomings mentioned above and the limited success of the last two NELP rounds, there are also some good prospects for increasing output from other new blocks:

- IOCs are still present and coming back. BP has been increasing its involvement in India's upstream sector with the agreement signed with RIL to in February 2011. BP would take a 30% stake in 23 oil and gas PSC operated by RIL in India, including KG-D6. RIL will benefit from BP's deep-water expertise, while remaining the operator. BP and RIL also created a 50:50 JV for the sourcing and marketing of natural gas in India
- New discoveries. ONGC made 24 discoveries in 2010/11 in domestic fields and 9 new pool discoveries.[9] Early 2011, ONGC announced a discovery of around 113 bcm (4 tcf) off the Daman coast, which could produce up to 7 Mcm/d.
- Partnering with companies. ONGC is reportedly looking to partner one of the American giants-ConocoPhillips. The terms of the proposed agreement reportedly include Conoco evaluating its participation with ONGC to develop both shale gas as well as deepwater fields

4. Imports

In 2010/11, India imported 12 bcm of LNG, mostly from Qatar, but also from Trinidad and Tobago as well as from a few other countries. In 2011/12, India started looking for more LNG due to difficulties with domestic supplies. While in 2009, LNG imports were expected to remain stable for the years to come due to growing production, the recent lower domestic output required companies to look for LNG. LNG imports over the first 8 months of 2011/12 increased to 10.3bcm, which translated into 15.5 bcm on an annualised basis. This would be a record for India, despite the relative high price environment. Qatar remains the largest source of supply to India, representing over 80% of its supplies. Until new LNG supply comes on line, this situation is not expected to change substantially. So far, India does not import by pipeline. While several projects are under consideration, they are still far from even taking Final Investment Decision.

There are no final numbers yet on the 12th Five Year Plan. In the draft approach from the Planning Commission released in August 2011, gas demand would increase by 50% from 2010/11 to 2016/17, and import dependency from 19% to 28.4%, or LNG imports be 2.26 times higher (28 bcm). According to press reports, imports would increase to 95 bcm (258 Mcm/d) by 2016/17. IEA's forecasts on demand and domestic production imply a supply gap of 18 bcm by 2015, increasing to 28 bcm by 2020 and 52 bcm by 2030. This highlights the uncertainties on supply and demand.

[9] Announced in January 2009.

Table 5: India LNG imports by country (bcm)

	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Abu Dhabi			0.09	0.08	0.13	0.16	
Australia			0.09		0.16	1.11	
Indonesia						0.08	
Malaysia			0.09	0.09	0.08	0.25	
Oman			0.27	0.27	0.41	0.35	
Qatar	3.49	6.98	8.24	9.43	8.34	8.16	10.67
Algeria			0.09	0.55	0.53	0.16	
Nigeria			0.09	0.77	0.38	0.32	0.32
T&T				0.24	0.23	0.68	0.66
Egypt			0.62	0.09	0.24	0.33	0.09
E. Guinea					0.42	0.25	0.17
Norway					0.08		
Russia							
Yemen							0.37
Others					0.17	0.68	0.28
Total	3.49	6.98	9.59	11.52	11.16	12.51	12.56

Source: IEA, Natural Gas Information 2010 and 2011.

4.1 LNG

4.1.1 Import infrastructure

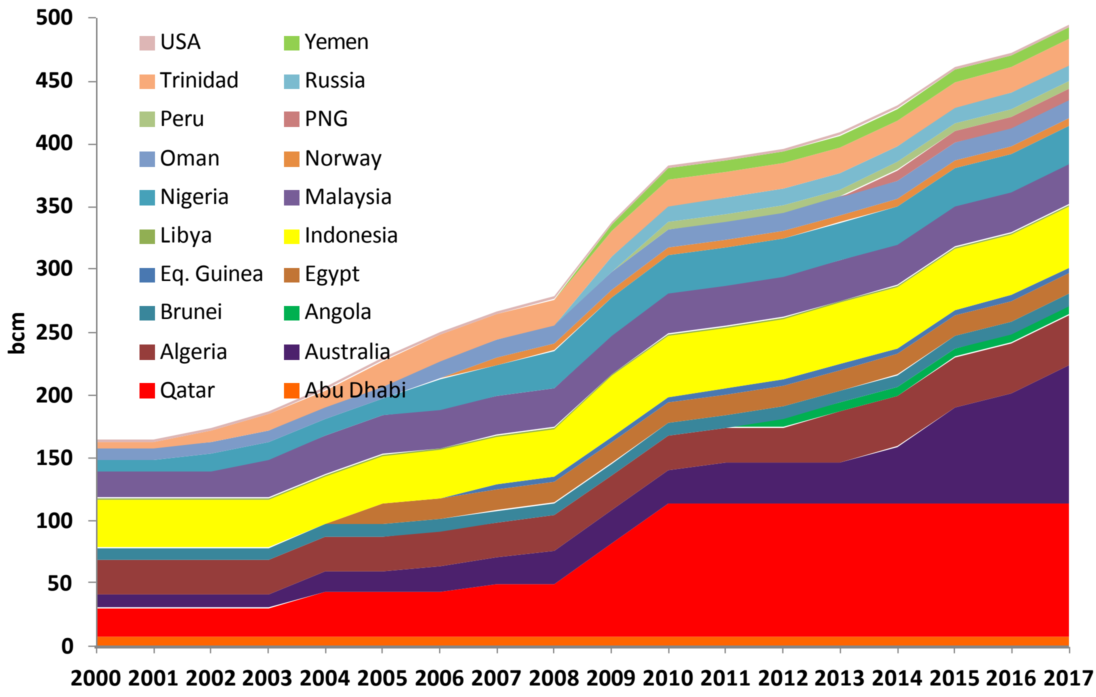
India started importing LNG in 2004, one year ahead of China. As of early 2012, there are only two operating LNG import terminals, Dahej and Hazira, representing an import capacity of 13.5 mtpa (18 bcm). LNG is the only import option for India in the short term. Pipeline imports could start in a longer term perspective.

Dahej started operating in 2004 and is operated by Petronet LNG Limited (PLL), a JV between GAIL, IOCL, Bahrat Petroleum (BPCL), GDF Suez, the Asian Development Bank (ADB) and ONGC. PLL expanded this terminal from 5 to 10 mtpa (6.8 to 13.6 bcm) in early 2009. Hazira started in April 2005, and is owned by Shell and Total. Its capacity is 3.5 mtpa (4.8 bcm).[10] Both are located on the north western coast, in order to serve the historical markets.

As of early 2012, two LNG terminals are under construction. The Dabhol-Ratnagiri LNG terminal has been delayed for some three years (initially planned for mid-April 2009), but is expected to start early 2012. Its capacity will be 5.5 mtpa (7.5 bcm), with about 2.9 mtpa (3.9 bcm) available for merchant sales. As breakwater facilities still need to be completed, it would only operate at a capacity of 1.5 mtpa (2.1 bcm) in a first phase and ramp up to its nominal capacity gradually to be fully operational by 2014. The second LNG terminal under construction is the 2.5 mtpa (3.4 bcm) Kochi, expected to be operational end-2012. This means that India’s LNG import capacity will reach 29 bcm by 2014.

[10] The capacity was initially 2.7 mtpa but was expanded to 3.5 mtpa in 2008.

Figure 4: Evolution of global LNG export capacity



Source: IEA, companies reports, pres releases.

There are nevertheless many other LNG import terminals currently planned, although none has reached FID so far. Both existing LNG terminals (Dahej and Hazira) plan an expansion. As far as other projects are concerned, it is unlikely that all terminals will come online. The key issue will be to find long-term supplies or an aggregator to support the project as it was the case for Hazira (with Total and Shell). So far, there is little gas contracted based on projects which have taken a FID, but additional volumes based on MOU have been secured (see below).

Those investments are likely to face some difficulties and delays related to lack of capital, constraints in or absence of domestic pipeline infrastructure and difficulties to secure new supplies, as competition from Japan, Korea, China and many South Eastern countries is growing. Existing and future pipeline infrastructure is important for future LNG regasification terminals. For example, gas from the Dahej terminal flows through Gail's HVJ pipeline as does production from the Gujarat coast. As a result, little spare capacity is available in this pipeline. This problem was particularly acute during summer 2009, when demand from the power generation sector in the region of New Delhi was exceptionally high due to the late arrival of the monsoon rains. India's projected growing appetite for gas makes it necessary to build additional infrastructure; additionally this would support the development of other regional markets, like Kochi does.

Table 6: India LNG terminals, existing, under construction and planned

Terminal	Partners	Capacity	Supply source	Start-up
Existing				
Dahej	Petronet LNG (GAIL, ONGC, Indian Oil and BPLC (each 12.5%), GDF Suez (10%), ADB (5.2%) and private shareholders (34.8%))	10 mtpa	Qatar – long term (7.5 mtpa)	March 2004
Hazira	Shell (operator, 74%), Total (26%)	3.5 mtpa	Merchant model	April 2005
Under construction				
Dabhol	NTPC, GAIL, Indian banks[11] (28.3% each) and the Maharashtra state Electricity Board (15%).	5.5 mtpa (1 mtpa initially)	n.a.	2012
Kochi	Petronet LNG	2.5 mtpa	1.5 mtpa for 20 years from ExxonMobil's Gorgon, Australia (2014-15).	2012
Planned				
Dahej exp	Petronet LNG	5 mtpa	n.a.	End 2015
Hazira exp	Shell, Total	1.5 mtpa	n.a.	2013
Kochi exp	Petronet LNG	2.5 mtpa	n.a.	2014.
Orissa	Petronet LNG	5 mtpa	n.a.	2015
Mundra Port	GSPC, Adani	5 mtpa	n.a.	2015
Ennore	TIDCO, OilIndia	5 mtpa	n.a.	2015-16
Mangalore	ONGC	5 mtpa	Possibly Oman, Qatar, Africa	n.a.
Maharashtra or Karnataka	BPCL	5 mtpa	Possibly Mozambique	n.a.
Dhamra	IOC	5 mtpa	n.a.	n.a.
Pipapav Port	EssarGroup, Swan Energy, possibly GSPC Gujarat Pipavav Port Ltd. Intends to become a partner	5 mtpa	n.a.	n.a.
Hazira exp	Shell, Total	5 mtpa	n.a.	n.a.
Haldia	Spice Energy	2.5 mtpa	Indonesia	2011
Kandla	Kandla Port Trust, possibly private companies	2 mtpa	n.a.	n.a.

Note: this data represents companies' expectations regarding online dates.

[11] The bank consortium comprises IDBI Ltd. (10.65% of the total shares), State Bank of India (8.67%), ICICI Bank (7.14%) and Canara Bank (1.87%).

Source: Company reports, press releases.

4.2.2 Finding LNG on global gas markets

India has only one active long-term LNG contract, with Qatar. It was signed to initially supply 5 mtpa (6.7 bcm) to the Dahej terminal. The quantities were later increased to 7.5 mtpa due to the expansion of the terminal's capacity. The pricing formula proposes a fixed price indexed to a JCC price of USD 20/bbl for the first five years until December 2008 (USD 2.53/MBtu); and then to link it to the average of JCC over 12 months. The second terminal operates on a merchant basis, so there is no contracted gas.

There is another long-term contract based on an LNG plant under construction. In May 2009, Petronet LNG signed a 20-year contract for 1.5 mtpa with ExxonMobil's for Gorgon's LNG (Australia). The plant is expected to start late 2014, and the LNG has been earmarked for Kochi. Gorgon's sponsors took the FID in September 2009. Petronet has taken a lower share in Gorgon than was first mentioned in early 2008 – 3.75 mtpa. It seems that Petronet had acquired more confidence with the start of the KG field and the fact that ample LNG supplies are available. In 2011, BG signed a HoA with GSPC for a 20-year contract for 2.5 mtpa starting in 2014. It would come from BG's global portfolio.

This puts total contracted LNG supplies based on long-term contracts based on plants existing or under construction to 11.5 mtpa (15.6 bcm), way below the capacity expected to be on line by 2014.

Indian companies have been also active securing LNG from plants which have not yet taken FID and based on medium- to long-term contracts, probably as the result of difficulties securing domestic gas supplies. In 2011, Gazprom signed LNG 25-year contracts with four Indian companies (3.4 bcm each), but the supply source is unknown. Deliveries would start between 2016 and 2018. Very few Russian LNG plants could be ready at that time. Although still at early stage of development, Vladivostok LNG (13.6 bcm/year) could be an option. In 2012, the APEC Summit will be hosted by Russia in Vladivostok and this political event could push forward the economic development of the region as well as the second LNG project in the Far East of Siberia. Another long-term contract is that between GAIL and Cheniere for the Sabine Pass LNG plant. This would be a contract for 3.5mtpa (5 bcm) with a pricing formulae indexed on Henry Hub, unlike the other contracts where the price was oil linked. So far, Henry Hub prices have been very low, even below USD 3/MBtu in January 2012, but the question is whether they would stay at low levels, for how long and how this would compare to other international gas prices. Discussions between Indian companies and other suppliers are continuing. Petronet has been in discussion with Algeria (Sonatrach) since 2007 over a 1.25 mtpa 25-year contract, and is interested in the Niugini project (Papua New Guinea).

Not all LNG supplies are based on long-term contracts. Since 2006, India has been importing many spot cargoes, not only to Hazira, but also to Dahej. In 2009, India has become a destination of choice for many Pacific and Middle East exporters due to increasing demand, proximity and netbacks relatively comparable, if not better, to the United States or the United Kingdom. Since the start-up of Sakhalin, Hazira and Dahej have received several Russian cargoes as Russia tries to keep exports East of Suez. Due to proximity, some Yemeni cargoes went to India instead of the United States. Petronet also signed a short-term contract of 1.2 mtpa with Qatar from March 2007 to June 2009. In 2010, Gail and Japan's Marubeni signed a 3-year deal for 0.5 mtpa per year, starting in 2011, while GSPC and Gazprom also concluded a deal for 0.3 mtpa for 3 years for the same period.

Therefore, most of deals signed with projects currently under consideration, or alternative supplies, would be needed to reach the lowest import levels under consideration (28 bcm). Assuming that by 2018, all long-term contracts mentioned above are active, this would mean some 35 bcm contracted by then. When markets were loose in 2009 and early 2010, Indian buyers were mostly looking at potential cheaper LNG alternatives priced on a spot basis (which was then half that of oil-linked price). This strategy was fine as long as markets were not tightening, but this happened in 2010 and 2011, notably after Fukushima which sent Asian spot prices to record levels and prompted Japanese buyers to look for additional long-term LNG. It is therefore now not only difficult to find cheap spot LNG, but there is also a lot of competition to secure the next wave of LNG. Most of the LNG arriving to the markets is already pretty much contracted, with the exception of Angola and Algeria. This is leading Indian companies to look at other sources, such as Russia or Mozambique.

4.2 Gas pipelines projects – a distant prospect

As of early 2012, pipeline routes appear to be a more distant option compared to LNG supply, but this does not mean they are no longer considered. Given India's needs, both pipelines and LNG will be needed to fill the gap between supply and demand in the long term. For India, there are not that many options in terms of supply sources. As of 2012, there are only two pipeline projects which could bring pipeline gas to India during the next 25 years window: the Iran-Pakistan-India (IPI) from Iran, and the Turkmenistan-Afghanistan-Pakistan-India (TAPI) from Turkmenistan. Russia could be an option, given the reserves, and the proximity but no project has been ever mentioned (unlike LNG). Another pipeline project from Myanmar has totally lost momentum, and does not seem to be considered any longer, while the pipeline from Oman to India seems an even more distant prospect.

Both pipelines transit through Pakistan, so that one pipeline moving forward is likely to undermine the participation of Pakistan to the other. Furthermore, Pakistan expressed its interest to source Turkmen gas via Iran through the IP pipeline. This would require a new pipeline to be built to connect Turkmenistan to Pakistan but also to agree on pricing issues. From the Indian perspective, the security issues in Afghanistan and Pakistan are important issues to tackle to enable good security of gas supplies.

4.2.1 The IPI pipeline project

The Iran-Pakistan-India pipeline project was launched in the 1990s. After long years of negotiations between Iran,, Pakistan and India regarding pricing and delivery terms, Iran and Pakistan finally agreed on 5 June 2009 to develop an Iran-Pakistan (IP) pipeline, India virtually withdrawn since the terror attacks in Mumbai in November 2008, but the pipeline still intends to be a trilateral project, the so-called "Peace Pipeline" or IPI. In 2009, Iran and Pakistan signed an agreement for Iran to supply Pakistan with 7.5 bcm/y for 25 years, with an extension for an additional five years in case of mutual agreement. In March 2010, Pakistan and Iran signed a Head of Agreement to build a 7.5 bcm pipeline by 2015.

There are nevertheless several issues that complicate the completion of the pipeline and India's participation, notably the development of Iran's resources, as well as pricing and geopolitical issues.

- Despite Iran's huge gas resources estimated at 29.6 tcm (as of end 2010), the country is a net gas importer as demand is increasing more rapidly than production. The huge and increasing requirements for reinjection, in addition to a booming domestic market, require substantial investments in exploration and production, but Iran is suffering from a poor investment climate due to international political tensions and the most recent developments make this unlikely to change in the short or medium term. Besides its huge domestic requirements, Iran is engaged in several export projects ranging from LNG to pipeline to the East (Pakistan and India) and the West (Turkey and Europe), but these projects are facing difficulties due to the recent tensions.
- Iran was originally thinking of having a gas price linked to a gas price formula similar to the Japanese LNG based on Japanese Crude Cocktail (JCC) price. However, to that would be added over USD 2/MBtu of transit and transportation tariffs to Pakistan, which could put this gas at a much higher price than APM price.12
- Geopolitical issues hampering the pipeline extension to India are diverse: they range from concerns about a safe transit through Baluchistan to the tense international relations. One important issue for India is represented by the history of mistrust and recent conflicts with Pakistan, in particular stability and security concerns regarding the Baluchistan province in Pakistan, through which a portion of the pipeline is planned. India would need strong domestic support to be dependent on Pakistan by accepting it as a transit route for part of its energy imports.

4.2.2 The Turkmenistan-Afghanistan-Pakistan-India pipeline (TAPI)

This proposed pipeline along a 1 680 km has been pending for more than 10 years and is a challenging one given the transit countries – Afghanistan and Pakistan. The proposed capacity would be 30 bcm/y, while capital costs are estimated at USD 8 billion. Security of the TAPI route through Afghanistan is an impediment, although, in 2008, the Afghan government made several pledges to address these concerns. In April 2009, the governments of the four countries signed a framework agreement to construct TAPI, stating that the pipeline would be built by a consortium of the countries' national oil companies. Afghanistan and Pakistan would get transit fees for gas transition their territories, based on an international cost of service benchmark.

Any progress in the pipeline would likely involve ADB assistance as they have been conducting feasibility studies in the past, but it is uncertain to what extent they would fund the project.

Another key question relates to Turkmenistan, which has been pursuing a strategy of diversification of exports. It has been able to balance its overdependence on Russia with rising exports to China (estimated at 16 bcm in 2011) and Iran, and is considering further

[12] Pakistan has also offered India the alternative option to buy gas at the Pakistan-India border from Pakistan and let Pakistan and Iran deal with the pipeline. However, Indian sources pointed out that this could put India in a critical situation for its nuclear relations with the United States.

options to Europe, India or increases to China (which recently mentioned 65 bcm). The major issue is the potential to increase domestic gas production. Gas reserves look promising, yet, Turkmen gas production has often missed the official optimistic targets. Additionally, the country is unlikely to be able to deal with many key projects at the same time. When gauging its options with Europe and India, Turkmenistan may choose to prioritise the former as the situation in Afghanistan remains very uncertain especially since NATO troops will progressively retreat and price negotiations with India and Pakistan are difficult. TAPI pipeline is a very short route, and thus potentially cheaper than the European route.

4.2.3 The Myanmar-India pipeline

A 1 575 km-long pipeline connecting the Shwe field to the A-1 block in Myanmar, in which both ONGC Videsh and GAIL own a stake (20% and 10% respectively), was considered to bring gas to India, passing through Bangladesh. The consortium of blocks A1 and A3 had recently declared a total discovery of GIIP of 5.35 tcf of gas. However, not much progress has happened on this front recently while the pipeline to China is currently under construction to start by 2013. As Chinese authorities have doubts on whether the 12 bcm pipeline would be full, it is unlikely that much gas would be available for India.

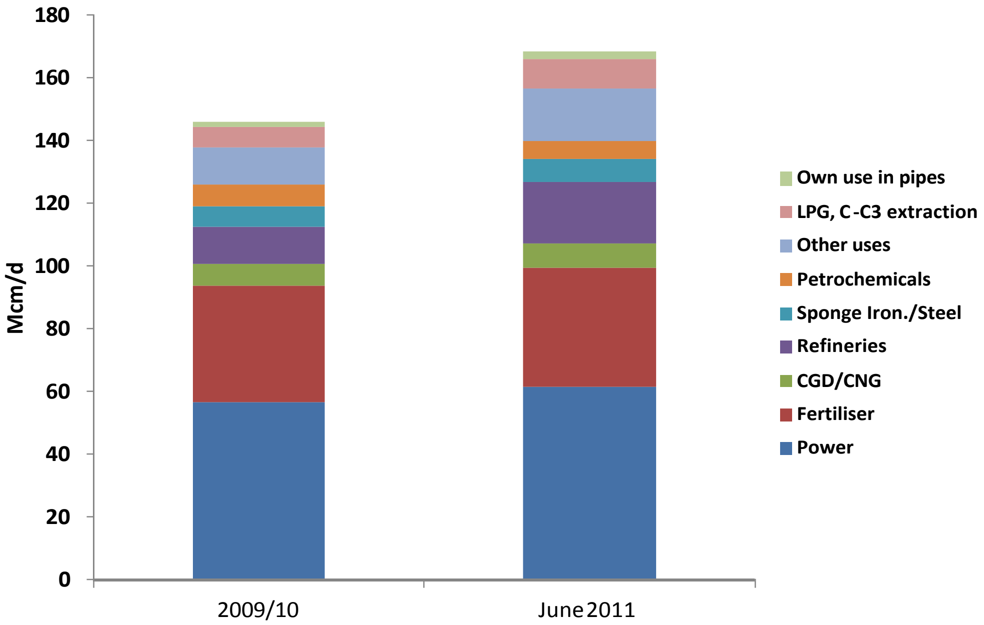
5. Demand

5.1 Analysis of current sectoral gas demand

Natural gas demand in India reached 168 Mcm/d (61 bcm) in June 2011. This is in contrast with the situation that prevailed until 2009, where demand was constrained by the lack of supplies available and is a clear result of the increasing availability of domestic supplies. For a very long period, potential demand was much higher than India's actual consumption: in 2007, the gap was as big as 35 bcm.[13] However, such constraints are likely to continue over the coming years, and the full year 2011/12 is already an example of such a trend.

Figure 5: India's gas use

[13] Fuel supplies availability and pricing natural gas, R. P. Sharma, RIL, 2007.



Source: Government of India.

The power sector is a key gas user, consuming some 40% of total gas use, followed by fertiliser producers with around a quarter. Both sectors strongly benefitted from the growth of domestic gas output; it was even surprising that such a volume got so quickly absorbed by the hungry market. Refineries have been among the big winners in terms in incremental gas consumption between 2009/10 and mid-2011, it remains to be seen whether this has been sustained with the drop of domestic gas production.

5.2 Forecasts

The demand forecasts from the 11th five-year plan (2007-12) show a wide gap between potential demand and actual demand. Indeed, according to this plan, gas demand would increase by between 37% and 58% over 2007-12 and the power sector be the main driver for incremental gas demand (see Table 7). However, while potential demand in 2008/09 was estimated at 72 bcm, it was 30 bcm higher than actual consumption, while demand for 2010/11 was to reach 97 bcm compared to an estimated level of 63 bcm. Unmet demand is still very high at around 30 bcm and rests essentially in the power sector and the industrial sector (around 40% of unmet demand each) with fertiliser production accounting for the rest. According to these forecasts, demand would reach between 89 bcm and 103 bcm by 2011/12. Considering the recent developments on the production side (see section on production), and that India is unlikely to import more than 18 bcm of LNG (more likely 15-16 bcm) in 2011/12, even the low demand number is far above the actual demand level estimated at 57-60 bcm, below the previous year's levels. The power sector, the industry and fertilisers are likely to be the victims of this gap between potential demand and realised consumption.

Table 7: Gas demand projections in the XI Five Year Plan (bcm)

Sector	2007/08	2008/09	2009/10	2010/11	2011/12	
	I	I	I	I	I	II
Power	29.2	33.2	37.6	41.6	46.4	32.5

Fertiliser	15.0	15.7	19.0	28.8	28.8	28.8
City Gas/Industrial	9.9	10.6	11.3	12.4	13.1	13.1
Sponge Iron	2.2	2.2	2.6	2.6	2.9	2.9
Other (Petrochem/ Refinery / Internal Consumption)	9.1	9.9	10.6	11.3	12.0	12.0
Total (Mcm/d)	**179**	**196**	**222**	**265**	**283**	**245**
Total (bcm)	**65**	**72**	**81**	**97**	**103**	**89**

Source: India Oil & Gas.

There are wide differences among the different forecasts for gas demand in India, even in the medium term. The Draft Approach to the 12th Five Year Plan foresees India's economy growing at 9% per year and therefore energy growing at 6.5% between 2010/11 and 2016/17. During the same period, natural gas demand would increase by 50%, and import dependency from 19% to 28.4%. According to other forecasts reported by the press, gas demand would double to reach 173 bcm (473 Mcm/d) in 2016/17, and from 180 bcm (494 Mcm/d) in 2017/18 to 221 bcm (606 Mcm/d) in 2021/22. Of the 173 bcm, some 44% would come from the power sector and 24% from fertiliser producers. By 2021/22, power producers would represent 51% of total demand while fertiliser producers may not see their demand increasing during 2017-22.

The discrepancies between the different forecasts can be explained by several reasons. There are not at this date official forecasts for the next Five Year Plan available to public, hence different forecasts reflecting work in progress. The increase reflects difficulties on the coal side, which implies that more gas could be needed. As mentioned before, this demand is "potential demand" and may not be met depending on the developments of Indian gas production and import infrastructure. The high scenario implies that a lot of LNG import terminals would need to be built and India to become an attractive place for LNG suppliers. Given the LNG contracted, this seems challenging.

5.3 Demand analysis by sector

5.3.1 Power generation

Understanding the evolution of the gas needs from the power sector requires looking at the whole Indian power sector. Analysing India's power sector is not the aim of this report though, but it is worth noting that the main issues are the lack of access to electricity for many people, electricity shortages both on an annual and a peak basis, and the need to attract investments in all parts of the value chain from generation, to transmission and distribution, in order to sustain economic growth, in particular if we are to see the 9% assumed in the 12th Five-Year Plan.

Future gas use in this sector will depend essentially on three factors: total electricity demand, gas availability and competitiveness of gas-fired plants versus coal-fired plants and other sources of electricity supply. India's impressive economic growth over the past decade has resulted in booming demand for electricity, but energy poverty represents a tremendous challenge. In 2001, 44% of households did not have access to electricity. Therefore, India is looking at new technologies such as IGCC, new clean energy sources including hydro, solar and wind in order to meet its growing demand and investigates the development of Carbon Capture and Storage (CCS) in a long-term perspective. India also considers nuclear despite a more difficult environment.

In order to provide electricity to more people, major investments will be required. Electricity shortages have been typically around 7% during the 1996-2006 period and the peak electricity shortage up to 14%. The current capacity as of December 2011 amounts to 186.7 GW, according to the Central Electricity Authority (CEA), with gas representing 9% versus 56% for coal and 21% for hydro. As of end-2011, there were 17.7 GW of gas-fired plants, two thirds of which have been installed since 1995. In any case, the growth of gas-fired capacity is on the agenda. According to the Committee on gas prices pooling, an additional 12 200 MW of gas-fired capacity is to be added by 2013.

Gas has benefited from the shortages of electricity and domestic coal which resulted in higher electricity prices, helping gas to be used base-load even with non-APM gas. Gas availability has been a constant problem over the 2000-09 period, but the situation has only started to improve since mid-2009. Previously, gas-fired plants were utilised at around 50% of their capacity. Before then, many gas-fired plants had been running on naphtha or remained idle when naphtha was too expensive due to the limited availability of gas. The CEA estimated that the shortfall of gas to the power generation sector over the period 2000-08 was between 18 and 28 Mcm/d (6.6 and 10.2 bcm). The year 2009 has seen a considerable improvement with KG-D6 coming on line. Since then, total thermal generation has been close to targets. The gas-fired plant load factor (PLF) has increased from 57% in January 2009 to 66% in April 2009 to 77% in April 2010. PLF in 2009/10 was around 10% higher than the same period one year earlier. Meanwhile, the PLF of lignite and coal plants declined due to shortages of domestic coal and failure to secure imports. In 2011, this situation seems to have however reversed in favour of coal due to the recent issues with gas supplies.

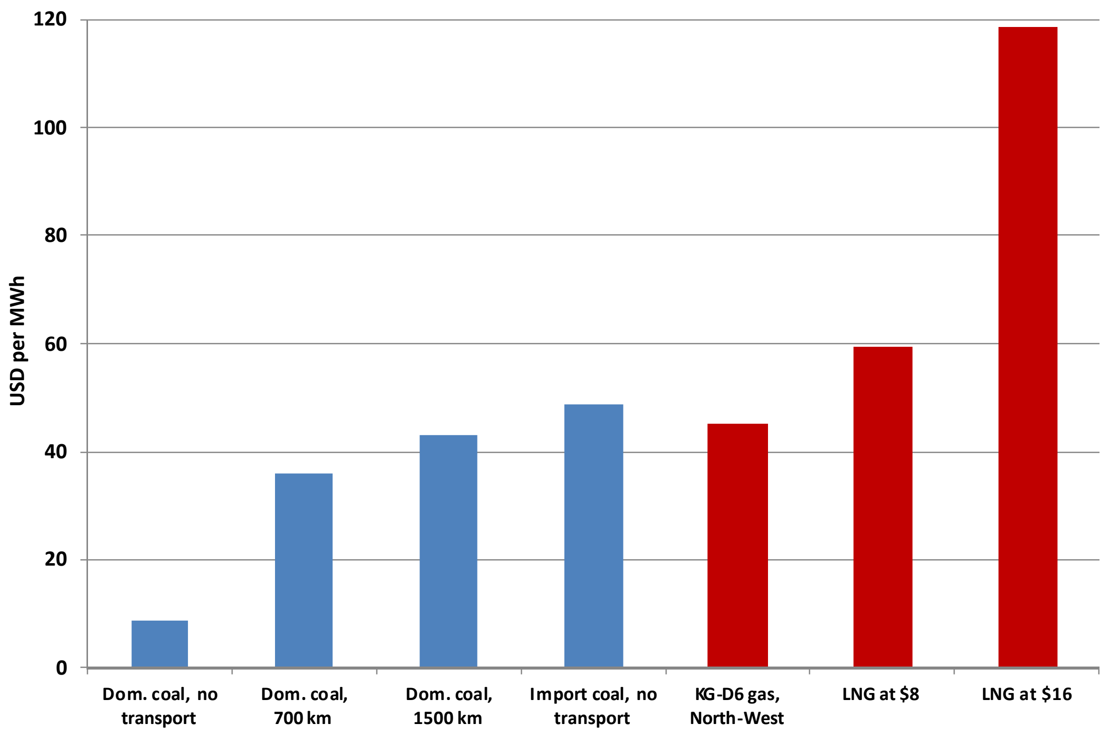
Another issue, probably the most important of all, is the competitiveness of gas-fired plants versus coal-fired plants. This will determine whether gas is used for base-load or to meet peak demand requirements, and therefore future gas demand requirements. This depends on many factors, including gas prices versus coal prices, as well as the developments in the coal sector. Indeed, coal itself is facing major issues which could affect coal-fired generation in the future. Most coal reserves are located in the eastern states, where generation already exceeds consumption. Actually, new power capacity would be needed in other regions, which implies for coal to be transported over long distances or imported. It is recognised that future coal demand will be partly based on imports, which are 30% to 50% more expensive than domestic coal. However, Indian power plants are not designed to take more than 10-15% of imported coal, while power producers may be reluctant to be less competitive against producers using cheap domestic coal. Alternatively, electricity transmission lines could be built between regions. Additionally, the policy aimed at reducing air pollution from coal use (including sulphur dioxide) may give an advantage to gas, which is already favoured as a transport fuel (see section on CNG), while the expected rationalisation of the Indian electricity grid could provide an opportunity for natural gas to play a larger role to meet peak demand.

In the following parts, gas-fired plants have been compared to coal-fired plants based on two approaches: looking at short-ruin marginal costs (SRMC) for existing plants and looking at levelised costs of electricity for future power plants.

For the SRMC, we have taken seven different power plants. The three gas-fired plants have an efficiency of 46%, which is a relatively high due to the fact that many power plants have been built since 1995. There are different gas prices: APM gas transported to the West coast, LNG imports at USD 8/MBtu and LNG imports at USD 16/MBtu, reflecting the current spread of import prices. LNG imports would be both consumed in the north-western region. Gas-fired plants have been compared to four coal-fired plants, three using domestic coal and one using imported coal. Plants using domestic coal have a 32% efficiency versus 37% for imported coal. Domestic coal prices are based on Coal India's data for 2012 (based on qualities of 3 700 to 4 000 kcal/kg at the mine, and 5 500 to 5 800 kcal/kg for coal transported). High quality coal is transported 700 km or 1 500 km; 700 km is close to the average historical transport distance for coal, while 1 500 km reflects a longer distance between production and consumption centres. Imported coal assumes a price of USD 120/t (plus a 5% import duty) and that the coal is consumed near the unloading port.

As expected, the cheapest option is the coal-fired plant using domestic coal on-site, despite its low efficiency and due to the very cheap price for this low grade type of coal. Gas-fired plants using KG-D6 (or APM) gas transported over the country could be competitive with imported coal (and is slightly higher than high quality coal transported over 1 500 km). As can be seen, using LNG for gas-fired plants put them at a very high gas level. Of course, the results can slightly vary depending on assumptions on prices and efficiency, but the ranking does not change significantly.

Figure 6: SRMC of coal-fired plants versus gas-fired plants

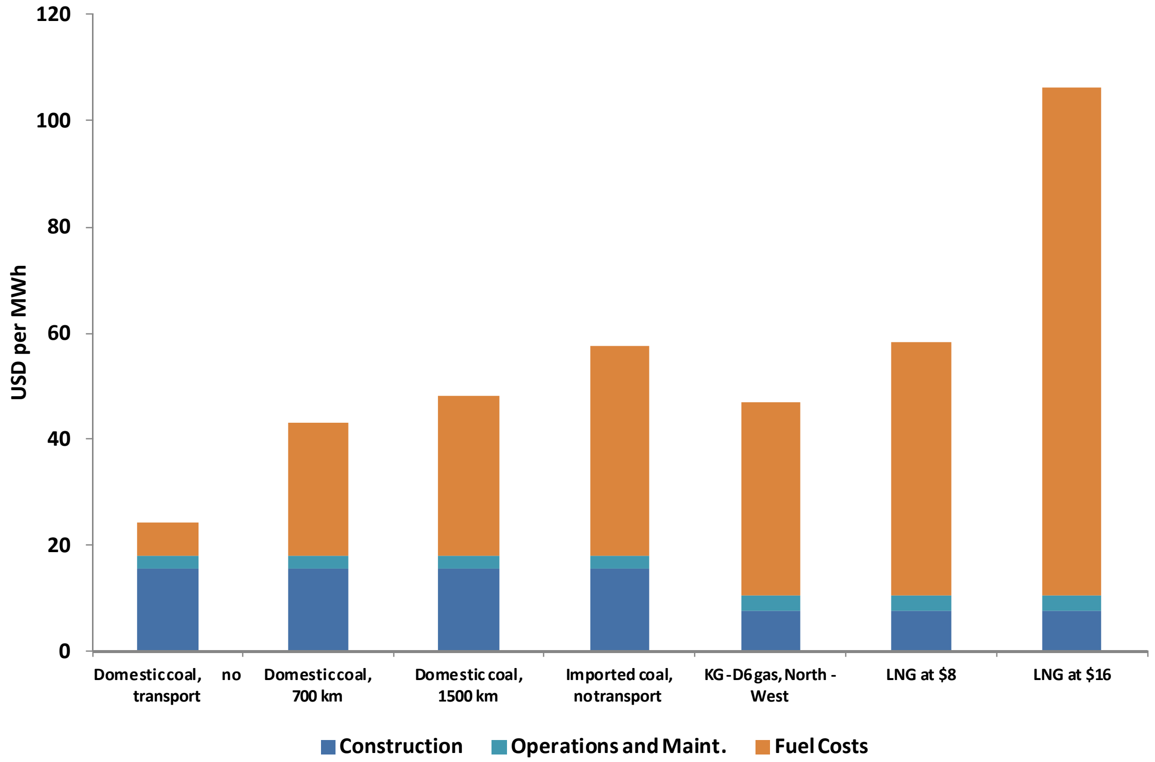


Sources: IEA, Projected Costs Generating Electricity, Medium-Term Coal Market Report 2011, Coal India.

In a second step, we use the methodology of levelised coasts of electricity. The assumptions are as follows: all plants have a 10% discount rate, gas fired plants have a lifetime of 30 years and a capacity of 250 MW versus 40 years and 800 MW for coal-fired plants. No CO_2 costs have been taken into account. All plants use the same price assumptions as for SRMC. As we look at new plants, the resultant costs appear lower than the SRMC; this is due to better efficiencies of the new power plants. The gas-fired plants have a PLF of 85% and a 57% efficiency. The PLF reflects a situation where supply is available for the plant, and is more optimistic than the current situation. All new coal-fired plants have a PLF of 85% and a 46% efficiency.

As expected, gas-fired plants using KG-D6 gas can be competitive against coal-fired plants using domestic coal transported over 1500 km or imported, but those using LNG at USD 8/Mbtu are still slightly more expensive than coal-fired plants with imported coal. Gas-fired plants using "cheap" LNG, APM gas or KG-D6 gas and located close to these supply sources could be competitive against some domestic coal-fired generation and coal plants using imported coal.

Figure 7: Generating costs of coal-fired plants versus gas-fired plants



Sources: IEA, Projected Costs Generating Electricity, Standford University, Coal India.

To conclude, coal-fired power has currently a competitive advantage using domestic coal in India, but in some cases depending on the location of the plant, future gas-fired plants could be more competitive. New gas-fired plants using APM/KG-D6 gas are competitive against coal plants using imported coal for base-load generation. The role of gas depends on where future coal-fired plants would be located, the evolution of local, imported coal prices and of LNG prices, and the coal supply and demand balance. If insufficient coal supplies are available, gas could be used more widely, even more if gas has become more expensive, while the cost would be passed to end users.

5.3.2 Fertiliser producers

Fertiliser producers are the second largest users of natural gas in India. They are a very politically sensitive area given the importance of the agriculture in India's economy. They use natural gas as a primary feedstock to produce urea, for which prices to farmers are capped by the government and actually below operating costs (Planning Commission, 2011). Urea represents around half of fertilisers used in India. Over the past five years, demand has been very variable, constrained by the lack of availability of gas. In 2009/10, several fertiliser units switched to gas as new supplies from KG-D6 became available; they consumed 26% of gas, but this share was slightly down in June 2011 to 22%.

The sector is key to maintain food self-sufficiency. Given the low urea prices, it is heavily subsided (subsidies increased from INR 15 879 crore in 2004/05 to INR 76 603 crore in 2008/09). It is unlikely that urea prices will be rapidly increased above operating costs (Planning Commission, 2011). This policy is becoming even more expensive with the gas prices increase in May 2010. Additionally, 17% of gas used by fertiliser producers came from imported LNG in 2010/11, down from 19% in 2009/10. Nevertheless, the alternative is either naphta or fuel oil, which are more expensive. It can be expected that most fertiliser plants will switch from naphtha and fuel oil to gas in the coming years, if enough supplies are available. Additionally, the Department of Fertilizers estimates that the additional 8 million tonnes of urea based on six planned projects would require additional 14.4 Mcm/d.

The main unknowns for future gas demand in this sector are the future price of imported urea, the price of gas used to produce urea (domestic APM gas and LNG). The policy of the government regarding fertilisers will also be a key. Discussions to phase out subsidies for urea production in 2012 have been ongoing, but no decision has finalised yet as of January 2012. The aim would be to gradually liberalise urea prices from the government's control, in line with phosphatic and potassic fertilisers. The government had already freed prices of the non-urea fertilisers. Another possibility is to import urea. There are already JVs in the Middle East, for example in Oman, which produce fertiliser at a lower price as gas is available at much lower prices (around USD 1/MBtu). But such a decision could face opposition from agricultural lobbies. A future shift to a greater role for imports would dramatically reduce domestic gas consumption and lessen the subsidy burden on the central government.

5.3.3 Industrial gas use

Industries have less priority than the power sector and fertiliser producers. Refineries nevertheless represented 12% of total gas use as of mid-2011, while sponge iron/steel, petrochemicals and other uses combined represented 17%. This means that industrial gas demand (excluding fertilisers) amounts to around one third of total gas consumption. The petrochemical industry faces similar challenges as the fertiliser industry in terms of access to cheap raw material. Due to the Gas Policy, many industrial customers (apart from LPG and petrochemicals) have no access to cheap gas and have to buy market priced gas from private companies. They need to accept the international prices or use another fuel (like naphtha). Nevertheless, the industrial sector has the potential to grow by 10% per year driven by India's strong economic growth. But industrial gas demand is still only a fraction of the potential market, as poor economics due to pricing issues, substitution difficulties for technical reasons, and non-availability caused by the lack of infrastructure together make industrial demand difficult to meet. The major opportunity for growth is in displacing naphtha use with oil prices at around USD 100/bbl.

5.3.4 CNG

According to the IANGV, there are 1.08 million of NGVs in India, which ranks fifth in terms of numbers of NGVs. It has increased four-fold over the past five years, but NGVs only represent a small share of total vehicles (1.32%). There have been two main drivers for NGV programmes in India: improving local air quality and reducing the costs due to oil product prices' subsidies. Air pollution has been a rising concern for GoI; in 2003, MoPNG released its Auto Fuel Policy to address these issues. Although it was recognised that liquid fuels would remain the backbone in the transport sector (with an upgrade of the specifications), the use of NGV and LPG would be encouraged. Over the past decade, CNG programmes were introduced in many cities, leading to a steady growth in the number of NGVs (buses, three-wheelers, taxis and small commercial vehicles). Most cities are located in Maharashtra and Gujarat, in the North-West of the country, where the ntework is most developed so far. Some individual state governments have taken actions such as tax exemptions, lower interest on loans to support the development of NGVs. Future growth of CNG's gas demand faces three major obstacles: expansion of the gas transport network to the cities; construction of the necessary infrastructure within the city, including refilling stations; and the availability of gas for CNG.

Conclusion

India has the potential to become a large gas consumer, and in particular gas demand could double over the coming decade. However, the future gas demand levels depend on many parameters, including performances of domestic gas production, international gas prices, development of new import infrastructure – notably LNG – and the competitiveness of gas in two key sectors – fertiliser producers and power producers. As over the past decades, natural gas demand is very price sensitive; India is likely to remain supply constrained if it fails to meet the challenges.

As of early 2012, the Indian gas market stands at a crossroads. Despite the dramatic increase of domestic production in 2009/10, substantial issues remain which will have to be solved for the Indian gas market to reach its potential. Four issues have been analysed within this report: regulation/policy, pricing, domestic supply, and import and transmission infrastructure.

The issues regarding policy are probably the most important: India needs a clear policy and regulatory framework in order to attract the investments needed in the energy sector, not only to sustain a high economic growth, but also to deal with poverty which leaves millions of people without access to energy. The role and powers of the regulators have to be clearly defined. India has opened up to private and foreign companies, although some progress still needs to be done in that area, as these want regulatory stability with minimum intervention from the state.

The pricing issue remains one of the most challenging as it determines the balancing point between supply and demand. The reform of May 2010 has reduced the disparities between different domestic gas prices, but the gap between domestic prices and LNG spot prices is getting wider. In the long term, additional LNG and pipeline supplies will be needed, but will also be more expensive than the current domestic gas prices. India is increasingly in competition with other countries, notably Asian countries where LNG demand is surging. Price levels are also key for the demand side, in particular for gas-fired plants and fertiliser producers. In some cases, gas-fired plants near production sources or import terminals could be more competitive than coal-fired plants, especially those using imported coal or domestic coal shipped over long distances. Gas use for fertiliser production depends on government policy towards subsidies, dependency on other countries, as fertilisers can be produced at a cheaper price in nearby Middle Eastern countries.

In the medium term, imports will be based on domestic production and LNG supplies. If India wants to reach the ambitious goal of increasing by 50% or even doubling its gas demand by 2017, massive investments will be needed on the production side as well as on import infrastructure. Despite the start of Krishna Godavari KG-D6 in 2009, there are big uncertainties on future developments of domestic production. Meeting higher demand levels implies securing additional volumes of LNG, but again this LNG will need to be competitive on the market. Although India is also located near significant resources of gas such as Turkmenistan and Iran, pipeline interconnections remain a more distant prospect given the challenges faced to develop pipelines.

In order to bring gas supplies to consumers, the transmission infrastructure needs to be enhanced. India is a vast country and the transmission network has been developed mostly in the North-West, and developments only start in other regions. New production centres and LNG terminals offer an opportunity to develop the transmission network. Finally, the development of new city distribution network needs to be accelerated. In both cases, the regulatory framework, in particular transport, distribution and end-user tariffs, should give enough incentives for the new infrastructure to be built, as well as to avoid regional disparities.

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