# Indian Gas Supply: Elixir for Growth or Priced Out of Reach?

*Chris Hansen*

### Introduction

The continued development of new gas supplies in western India will have a significant impact on electricity markets and new investment in power, fertiliser and other industrial sectors. However, rising international oil and gas prices and the preponderance of gas contracts benchmarked to crude prices have increased prices of imported gas supplies and may scupper demand growth. This article surveys the gas supply situation in the sub-continent and examines the emerging LNG regassification market in western India, and how electricity and industrial companies may respond.

### Background

Power and fertiliser sectors currently account for 80 per cent of gas demand in India, 5.7 billion cubic feet (bcf)/day, a total which is projected to grow to more than 0.6 bcf/day by 2010. The total demand for gas in Gujarat alone is approximately 2.3 bcf/day in 2005 and by 2009 demand is projected to increase to 3.2 bcf, a 40 per cent jump. New demand will be driven by sanctioned power plants, (e.g. Torrent and Essar's captive/merchant plants), fertiliser manufacturers and the Gujarat State Petroleum Corporation (GSPC) for resale to retail customers and for state-owned industries.

To meet this demand, India is pursuing supply from the gulf via LNG and several large domestic sources delivered by pipelines. In recent months, state-owned Petronet has commissioned its first LNG regassification terminal in Dahej, Gujarat on the western coast to import 5 (growing to 10) million tonnes/yr and Shell plans to receive its first LNG cargos in June of 2005 at its Hazira facility. (Natural gas is typically measured in cubic feet or $m^3$ or in energy content, for example million British Thermal Units (MMBTU). LNG is typically quoted in metric tonnes per annum (mtpa). For simplification these units are used throughout. To convert, 1 million tonnes of LNG is equal to 50.9 billion cubic feet (bcf) or 1.44 billion cubic metres (bcm).)

In addition, Reliance and ONGC have announced plans to bring an estimated 14–25 trillion cubic feet (tcf) of new gas finds from the Krishna-Godvari Basin to major consumption centres across the country. At first glance, it would seem that India is now poised for its own version of the 'dash for gas': high demand for electricity, ageing power infrastructure, a new regulatory climate and newly discovered large supplies of natural gas have provided a confluence of forces, which may well make gas the fuel of choice for Indian power and industrial companies.

The future of gas in India in the medium term depends on two main factors. First, whether gas prices will remain low enough to drive reticulation and industry investment vis-à-vis coal and other fuel options; and second, whether an adequate gas pipeline network and regulatory structure for gas transport will be created to send clear, stable investment signals to the market. The two factors will reinforce each other; e.g. high gas demand is likely to provide the political pressure to solve access and regulatory issues, and better regulation/access will increase gas demand.

The most likely fuel competitor is coal, which can provide the lowest cost electricity in some situations, such as a pit-head power station with marginal costs less than Rs1/kWh and levelised cost of Rs1.5/kWh. However, coal supplies are currently constrained by lack of mining capacity and railroad transport bottlenecks. The Indian government has even had to restrict supplies to several coal-fired stations in 2005 due to low production tonnage and is considering cutting all coal allocations for non-power plants to ensure power facilities can operate. Compounding the coal shortage for western India are the added costs of transporting coal from the eastern coal fields. To try to address this problem, Gujarat has announced investment in a 2500 MW lignite pit-head plant as well as a joint venture with Madya Pradesh to build a 2000 MW coal plant that proposes to use nearby captive mines for supply. Both projects are far from financial closure and it remains to be seen whether either state will be able to afford the projects. The other possible solution is to use imported coal at the port to generate power, but with estimated levelised costs of Rs2.25/kWh and plenty of fuel price risk, this may not be viable. In the long term, even with more coal production, Indian rail infrastructure will struggle to move enough coal to keep up with demand and pithead plants will require huge transmission investments to deliver the power to demand centres. Given the poor supply and transport situation, this article will concentrate on gas options.

### LNG Supplies and Pricing Variables

In the short term, the two LNG regassification facilities in Gujarat, Shell's Hazira and Petronet's Dahej, are slated to receive as much as 423 bcf (12 bcm) by the end of 2010, compared with 812 bcf (23 bcm) total Indian consumption in 2001. This LNG goal may prove ambitious if prices cannot be reduced and 'guaranteed' for the anchor customers. LNG price of supply contracts have historically been tied to oil price baskets, an arrangement that acts to effectively reduce gas as an alternative power fuel during periods of high oil prices and put the brakes on new CCGT investment. Nervous private power companies and industrial consumers such as Torrent have stated that gas prices over $3.5/MMBTU will make power production unviable. Thus forcing the question: will new gas supplies be priced out of reach for Indian markets?

Reducing price risk may require using a more inclusive basket of fuels to index gas prices, such as adding international coal prices to establish contracts, rather than just oil linked pricing or using longer-term contracts with 'manageable' ceiling tariffs. For example, the recent agreement signed with Iran for LNG has used a two-phased deal to overcome the current high crude prices. For the first three years of the contract (2009–2011), Iran will sell 7.5 million tonnes/annum (mtpa) at a fixed price of $2.97/MMBTU, and then will use a Brent indexed price with a $31/b ceiling and a $10/b floor, or $3.21 and $1.82/MMBTU, respectively. In addition, Iran offered the Indian government a 30 per cent stake in the related liquefaction plants and a 20 per cent stake in the 300,000 b/d Yadravan field plus 30,000 b/d from the Jufier field.

One advantage that India does have in the increasingly global LNG trade is location. LNG transport costs are directly related to distance and India is the closest market for Persian Gulf-sourced LNG. In comparison, the transport costs from Qatar to major regasification sites are estimated in Table 1.

**Table 1: LNG Transport Costs from Qatar**

| *Qatar to; Location* | *$/MMBTU* |
|---|---|
| Dabhol, India | 0.28 |
| Fukuoka, Japan | 0.95 |
| Guangdong, China | 0.80 |
| Long Beach, USA | 1.71 |
| Everett, USA | 1.41 |
| Milford Haven, UK | 1.13 |

Source: *Gas Matters* shipping calculator, 2005

This spread means that India has an arbitrage margin of more than $0.5/MMBTU when compared to its principle demand 'rivals' in East Asia. However, the Japanese and Korean markets have historically supported high prices, currently above $5/MMBTU spot price, with their high value-added export industries, which may make this spread too small for India to benefit in an era of tight LNG supply and high crude prices. Currently, the LNG imported by Spain, France, Belgium and Korea is priced around $6.25/MMBTU on a long-term contract. US gas prices are now hovering well above $6/MMBTU and are likely to stay at that level for the short term. However, futures contracts for early 2006 show prices below $5 as expectations of increased supply are factored in. At the $6 level, US LNG terminals look very attractive on a netback basis and could pull supply away from the Indian market as suppliers will not under-price LNG sales when there is a large demand in the world market.

Petronet's Dahej and Shell's Hazira LNG projects in Gujarat benefit from the relative proximity, and thus a sizeable transport margin, of LNG liquefaction plants in Oman and Qatar to source 'cost competitive' gas. The cost structure for the gulf-sourced LNG includes $0.30/MMBTU for transport and regassification charges, computed by the Indian Tariff Commission using a return on equity of 12 per cent, at $0.54/MMBTU, for a total gas at terminal price of less than $3.50/MMBTU under current supply agreements. The first tranches of the gas have been sold by Petronet for $4.87/MMBTU plant gate in Gujarat, and about 6 cents more in northern India to pay for pipeline costs. The quick sale of this regassed LNG to industry for non-power use demonstrates large pent-up demand for gas and indicates that the market for near $5 gas has some depth. This LNG, priced at nearly double the state subsidised gas price of $2.5/MMBTU bodes well for Shell/Total as they continue to negotiate deals for the new LNG capacity that will be online in June 2005. However, the short-term sales contracts may not be sustainable if LNG prices remain high or if a cheaper alternative is available from new pipeline supply.

**Pipeline Supplies of Gas for Western India**

The current gas supply is principally from the associated gas found in the Bombay High fields and is distributed through the HBJ pipeline. The state controls the distribution of this gas by offering subsidised rates to power and fertiliser firms. This limited supply of price controlled gas is virtually unavailable to industry and the government is now considering price hikes and full deregulation as it did in the petroleum market.

The most promising new sources of domestic gas supply in India are the discoveries in the Krishna Godvari Basin. Development plans indicate that the production and delivery infrastructure will be available by 2007, but uncertainty over total recoverable gas reserves (estimated at 3–25 tcf) and a number of regulatory and land purchase issues will likely slow the pipeline completion. Reliance has committed Rs150 billion ($3.3 billion) for the two-phase development of its offshore blocks, with an initial production of 40 million $m^3$/day of gas (1.4 bcf). Water depths in the basin vary from 400 metres to 3000 metres. The project may be held up however by pipeline issues as Reliance is threatening not to develop its holdings in the basin unless state-owned GAIL concedes its current statutory monopoly on inter-state pipeline connections.

On the western side of the country, Cairn Energy has announced gas finds 75 km south of the operator's giant Mangala oilfield development in Rajasthan. Cairn is now moving to drill an appraisal well to determine the reservoir size. New pipelines would also be needed to bring this gas to market.

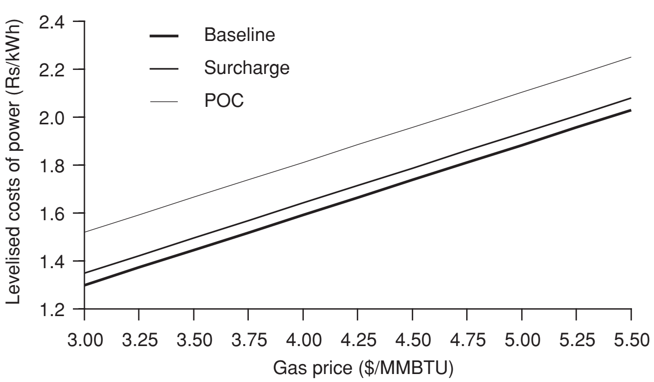
The prospect of international gas imports via pipeline has also been picking up steam. India has signed a long stalled agreement to import gas from Myanmar (Burma) using a $1 billion pipeline across Bangladesh, according to a joint statement from the three governments in January 2005. The agreement is the first international gas pipeline for India and was completed after years of political delays from Bangladesh. The sweetener was a bilateral agreement with India allowing it to increase trade with Bhutan and Nepal. 'We proposed for a corridor to transport goods to Nepal as well as to import hydroelectricity from Nepal and Bhutan. We have also urged India to narrow the huge trade gap between India and Bangladesh,' said Bangladesh's Energy Minister AKM Mosharraf Hossain.

The other main international option is the long touted Iran-Pakistan-India pipeline. The projected 2775-kilometre pipeline would cost $4.16 billion to build at current prices. However, the project faces many hurdles, not least of which the tensions between India and Pakistan. The USA has also entered the fray by increasing pressure against the project under the belief that such a project would aid Iran's economy, turn India and Pakistan into key strategic allies of Iran and reduce US leverage to thwart Tehran's nuclear programme. With the new Iran LNG deal in progress, and growing political hurdles, it is doubtful the pipeline will come to fruition before 2015.

## Gas Demand and Price Sensitivity

Regardless of the source of gas supply, the price sensitivity of the Indian power market will be a major factor in gas sales growth. Figure 1 displays the results from a price modelling exercise, assuming a weighted average cost of capital of 17.5 per cent and $600/kW overnight cost for CCGT capacity – this cost is defined as the total resources needed to build a power plant including accounting for capital expenses during the time of construction, land costs, equipment, engineering and commission expenses. The additional lines in the Figure examine the effects of parallel operations charges and additional cross-subsidy surcharges that may be levied by the state on captive and independent power producers.

**Figure 1: Gas Price Sensitivity for CCGT in India**

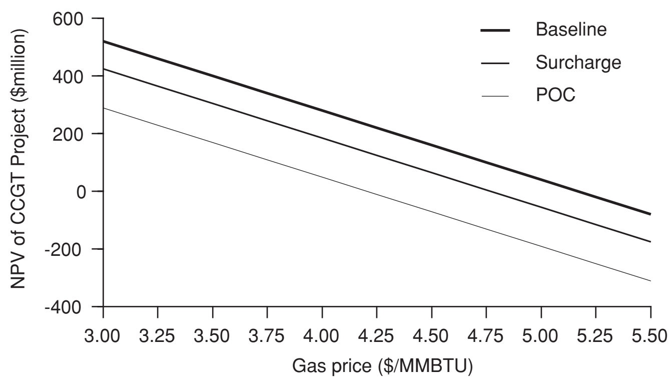



For the baseline case, a competitive levelised cost of power can be generated up to approximately $4.75 for captive use and $4.00 if parallel operations charges are levied. Figure 1 indicates that the high tariffs currently charged by the GEB to industrial consumers, more than Rs4.25/kWh in 2005, can be undercut even at high gas prices. As a result, the gas demand market for power production sold to industry should prove robust even when crude-linked prices are high.

For power plant investors, the other measures to consider are the NPV and the IRR of power projects and Figure 2 displays the results over a range of gas prices.

The baseline case indicates that $3.50/MMBTU gas would yield a NPV of $400,000,000 for a 30-year project, which corresponds to a 10 per cent IRR assuming a Rs2.5/kWh price for the power and neglecting plant size effects. Possibly more threatening than the gas price volatility is the unsettled regulatory issue of parallel operation charges (POC) and surcharges. Looking at the gas price scenario of $4.25, the project NPV dives from more than $200,000,000 in the black to negative value with the addition of the charges. This adds to the argument that gas prices are not the biggest source of uncertainty for power producers, especially if long-term contracts can be used to hedge price and currency risk. Instead, companies face more pressure from the political and regulatory regime to make gas projects profitable.

**Figure 2: Net Present Value of CCGT Projects in India**




## Gas Regulation and Tax Considerations

While the gas regulatory picture is still somewhat cloudy, and the national gas policy still in draft form, there have been positive signals for gas developers. The recent reduction in gas sales tax in Gujarat from 20 to 12 per cent, and the Indian Supreme Court's decision to strike down state regulatory authority over gas have both been reassuring to investors. Going further, the state-owned National Thermal Power Corporation (NTPC) has petitioned the Gujarat government to lower them further to 4 per cent. Competition between states to attract LNG facilities may lead to a tax reduction 'arms race,' which will likely lead rates to fall as a result.

Reports in July 2004 indicated that Gujarat Gas (a BG Group company), India Oil Company (IOC), Reliance (through Gujarat Adani Energy Ltd.), GAIL and GSPC are all pursuing gas transmission and distribution projects. The biggest commitment to date is GSPC's February 2005 announcement of investments totalling more than Rs 50 billion for 2500 km of transmission pipelines in the state. More transmission to serve industrial, CNG transport demand and urban areas is needed, but with a state company dominating the ownership of pipelines, open access may be an issue. The 2003 national gas plan calls for a 25 per cent overcapacity margin for all new pipelines and sets out a goal of achieving open access for all buyers and sellers. With proper implementation, this will reduce the market power of gas transport companies. On the trading side, there are already 25 active players in the market, representing both private and state-owned firms. However, India's track record on opening network industries is mixed at best, with the telecom sector the only notable bright spot.

### Conclusions

In summary, the dash for gas faces several major hurdles including high prices leading to demand destruction and regulatory uncertainty. Gas prices over $4.75/MMBTU will make gas-fired power generation difficult in most scenarios, thus both pipeline gas and LNG suppliers will have to be wary of price elasticity in the Indian power market. Innovative contractual arrangements in which power plant owners bear less of the price risk are needed for the dash to continue. The first adopters are likely to be large-scale CCGTs and industrial plants needing process heat or firms looking to escape high power tariffs from the state electricity boards. Looking beyond gas prices, it is likely to be regulatory and taxation decisions that will have the greatest impact on gas demand, and policy makers will have to be wary not to hobble investment and risk losing a gas-fuelled elixir for economic growth in India.



# Oil Production Expectations outside the Middle East

## Andrew Hayman considers West African production growth from 2005 to 2010

The West African margin continues to attract significant attention from the oil-consuming nations, most notably the United States. In a time of increasing uncertainty of oil supply, particularly from traditional OPEC partners in the Middle East, the USA is looking to supply its ever-hungry economy from partners in West Africa – notably, but not exclusively, Angola and Nigeria. It is no coincidence that President Obasanjo of Nigeria was the first African leader to be received in Washington, in December 2004, after President Bush's re-election to a second term. During his visit, at a forum held by the influential Leon Sullivan Foundation (whose President is ex-US Ambassador to the United Nations, Andrew Young), President Obasanjo said that Nigerian imports would rise from 7 to 15 per cent of US demand. Likewise, President dos Santos of Angola was received in Washington in May 2004.

The US domestic consumption is projected at 20.9 million barrels of oil per day (Mb/d) in 2005, with a 2 per cent per annum growth thereafter. Imports consisted of 12 Mb/d in 2003, or 60 per cent of demand. It is this latter figure, showing the growing dependency of the USA, which is driving oil politics (Figure 1).

The traditional top producers are shown in Figure 1. But with obvious long-term problems in Iraq, tensions with President Chavez of Venezuela, and ongoing ideological differences with Mexico, the USA is looking to secure long-term ties with the African producers. Both Nigeria (currently no. 5) and Angola (no. 7) will move up in the scale of suppliers to the United States.

Major US companies such as ExxonMobil and ChevronTexaco seem to be comfortable working in Angola; industrial projects get done in acceptable time-frames and according to plan. The country is now producing over 1.1 Mb/d (November 2004), and in the last year has successfully put on stream the Exxon-Mobil operated deepwater field Kizomba A (to reach 250,000 b/d in Q1 2005). Girassol-Jasmim, operated by Total, now contributes

**Figure 1: US Oil Production, Consumption and Imports**