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Gas Pricing Reform in India:

Implications for the Indian gas landscape

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1. Introduction

Most discussion on the future of the market for internationally traded gas focuses on the 'swing towards Asia'. Specifically, China and India, the world's two most populous nations, are frequently highlighted as major drivers of future demand. Yet, there is considerable ambiguity over the assumptions underpinning this observation, particularly with regards to India. For instance, in its 2014 New Policies Scenario, the International Energy Agency (IEA) forecasts that non-OECD demand will continue to constitute the majority of world gas demand, growing from 53% (1,806 Billion cubic metres) in 2012 to 61% (3,035 Bcm) in 2035. However, within this, while the share of China and India combined will grow from 11% in 2012 to 24% in 2035, India's share will grow from 3-7% (as opposed to China's, from 8-18%) - and as a percentage of world demand, it will grow from 2-4%. The proportion of gas in India's primary energy consumption will rise from 7-9% but will be nowhere near enough to displace either coal or oil (44% and 25%) by 2035. These projections suggest that India's contribution to world gas demand will be lower than generally perceived.

In fact, despite several years of high economic growth in the last decade[1], it is difficult to make a confident and accurate assessment of India's potential as a major Asian gas market. Official government forecasts carried out within a central planning framework[2] tend to be overly optimistic, whereas projections by multilateral organisations tend to be cautious but confused. The reason for this lack of clarity is that the Indian gas sector is broadly characterised by two moving parts: one which has prices and quantities set by the Indian government, and another which utilises gas at market (LNG import) prices. Additionally, there is some overlap between the two, further complicating attempts to assess these as separate markets. *The lack of a clear pricing signal therefore makes it difficult to determine future levels of demand.*

This paper analyses whether or not recent reforms to the pricing of domestic gas could potentially change the Indian gas landscape by making price signals clearer. The first announcement on the recent reforms to the system of domestically produced gas was made in June 2013.[3] These proposed breaking the (capped) link with Brent Crude in the existing pricing formula for the majority of domestically produced gas, and linking it instead to a weighted average price of a set of international prices, including US Henry Hub, UK National Balancing Point, netback of LNG prices to Japan, and netback of India's contracted LNG imports. Under this proposal, the setting of gas prices was to move from the purview of the government to that of 'market forces'.

The reform proposal drew mixed reactions: it was initially welcomed by Indian upstream exploration companies – both public and private - which announced that the lifting of price controls would enable them to invest in exploring difficult offshore fields and in developing marginal fields, potentially reversing the decline in domestic production. On the other hand, it was opposed by downstream consuming sectors which depend heavily on a lower gas price to maintain low retail prices for their consumers – primarily the fertilisers and power sectors, which collectively account for 70% of gas consumption and serve a large section of India's predominantly low-income agricultural population.

The government was therefore faced with a dilemma: whether to reform gas pricing to incentivise domestic exploration and production whilst risking price rises downstream, economic impacts on the agricultural sector and the potential loss of electoral support, or, continue to control gas prices (which

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[1] Followed by an economic slowdown in 2012/13. The IMF has predicted growth of 7.2 percent for 2015.

[2] Jain (2011)

[3] The reforms were based on recommendations by a specially constituted government committee - the Rangarajan Committee. Summary at http://eac.gov.in/pressrel/press_psc0201.pdf

were \$4.20/MMBtu prior to the recent price reform) whilst importing LNG at two or three times the domestic price to make up the deficit between production and consumption.[4]

The nature of this dilemma has been mainly political. This is reflected in the fact that implementing the reforms has been postponed three times since first being announced. Originally due to take effect on 1 April 2014, it was postponed to 1 July upon the request of the Election Commission, the body monitoring India's General Elections during April.[5] The new government, formed in May 2014 by the former main opposition party which won an absolute electoral majority, further postponed the decision until October 2014, and then to 1 November 2014, whilst instituting a new review of the original recommendations. This led to a prolonged period of uncertainty within the Indian gas sector.

On 18 October 2014, the new government announced that it would implement a modified version of the originally proposed formula for gas pricing from 1 November 2014. This removed the Japan LNG and Indian import netback price markers, and included the Alberta Reference price and Russian domestic gas price instead in the computation of a volume-weighted average price for domestic gas.[6] The new formula will be reviewed on a six-monthly basis. The most recent review, on 1 April 2015, set the price at \$4.66/MMBtu.

There are, arguably, medium-term solutions to the price-subsidy relationship which characterises the problem of gas pricing in India – one proposition has been that the increase in government take that will result from taxes and royalties paid by upstream companies on the back of a higher gas price could be utilised to offset the subsidy bill. However, as this paper shows, this 'feedback loop' is contingent on the effectiveness of the reform in increasing production levels. Further, there are underlying nuances to the problem, which are described in this paper, and which preclude any straightforward solutions.

This paper looks at the impact of gas pricing reform in India on the outlook for its 'gas landscape' in terms of three important questions:

- First, could gas pricing reform reverse the recent decline in domestic production?
- Second, could it lead to new upstream investments in gas?
- Finally, what is the impact of the reform on downstream consuming sectors?

The paper begins with a description of gas pricing mechanisms in India, followed by an overview of demand, supply and consumption. It then delves into the three broad questions posed above, and concludes with observations on whether reforms to gas 'price formation' (as opposed to 'price level') in India are in fact achievable, or whether they will continue to elude successive governments, and on whether India can ever be Asia's next gas market 'Goliath'.

Section 2 begins by describing the system of gas pricing in India, and analyses the new reforms. Section 3 discusses the two-tier structure of demand for gas in India, and the main drivers of the market for gas. Section 4 looks at the potential impact of reforms on domestic production and on facilitating new investments in exploration. Section 5 analyses the impact of reforms in the main consuming sectors, which underpin the question of whether pricing reforms are possible and sustainable. Section 6 discusses the implications for India's LNG imports. Section 7 summarises and concludes with some observations on potential future developments.

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[4] The recent fall in oil prices has meant lower prices for LNG sold on oil-linked contracts in Asia (although they are still higher than domestic gas prices). This is discussed further in Section 6.

[5] This was done on the grounds that new policy changes in the run-up to the election could have violated the Election Code of Conduct.

[6] This increased the price from \$4.20/MMBtu to \$5.05/MMBtu, based on Gross Calorific Value, for the period 1 November 2014 - 31 March 2015. The price for 1 April – 30 September has subsequently been set at \$4.66/MMbtu. This is discussed further in Section 2.5.

2. The Structure of Gas Prices in India

At first glance, gas pricing in India appears notoriously complicated, as there are a variety of different prices at the wellhead. In a nutshell: *the price of domestic gas to producers is set according to the terms of the fiscal regime that governs a producing field.*[7] To this are then added transportation costs, marketing margins, and state taxes to obtain the delivered price for gas (see Figure 1). As states have fiscal autonomy over indirect taxes, these tax rates tend to differ between states.[8]

Broadly, there have been three fiscal regimes for gas exploration and production in existence at any one time.[9] Producing fields thus operate under parallel fiscal systems, leading to different prices at the wellhead.

- *The Nomination regime* (also known as the Administered Pricing Mechanism or 'APM'), existed prior to the liberalisation of the upstream sector in the 1990s, covering most of the 'legacy' fields of the two largest NOCs – ONGC and OIL.

- *The Discovered Fields regime* (also known as the Pre-New Exploration Licensing Policy regime or 'Pre-NELP') was a semi-liberalised system brought in during the early 1990s to replace the Nomination regime, enabling joint ventures between private companies and the NOCs – which typically had a 30% carried interest[10].

- *The New Exploration Licensing Policy (NELP)* replaced the Pre-NELP regime in 1999, and was the main fiscal regime for upstream exploration and production as of March 2015, based on Production Sharing Contracts.

Table 1 below illustrates differentiated gas prices in India under the different regimes (prior to the recent price reform), as well as those for LNG imports.

Table 1: Gas Prices under Different Regimes *prior* to Gas Price Reforms (In $/MMBtu)

Regime	Price
Nomination Regime (APM)	$4.20
Discovered Fields (Pre NELP) Regime	$3.50 – $5.73
NELP Regime	$4.20
LNG Spot	$12.52 - $17.44
LNG Long Term Contracts[11]	$6.97 - $9.06

Source: GoI (2014b); Jain (2011, p.111)

In January 2014, the government announced that it would adopt a new fiscal regime to replace Production Sharing Contracts with a simpler 'Revenue Sharing Contract'. However, as of March 2015 this had not been implemented.[12]

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[7] Sen (2012); Jain (2011)

[8] Plans to implement a uniform Goods and Services Tax (GST) regime across states by April 2016 are unlikely to include 'energy', as states earn a large proportion of their revenues from it.

[9] Sen (2012) and Jain (2011) provide a discussion on the evolution of India's upstream fiscal regime.

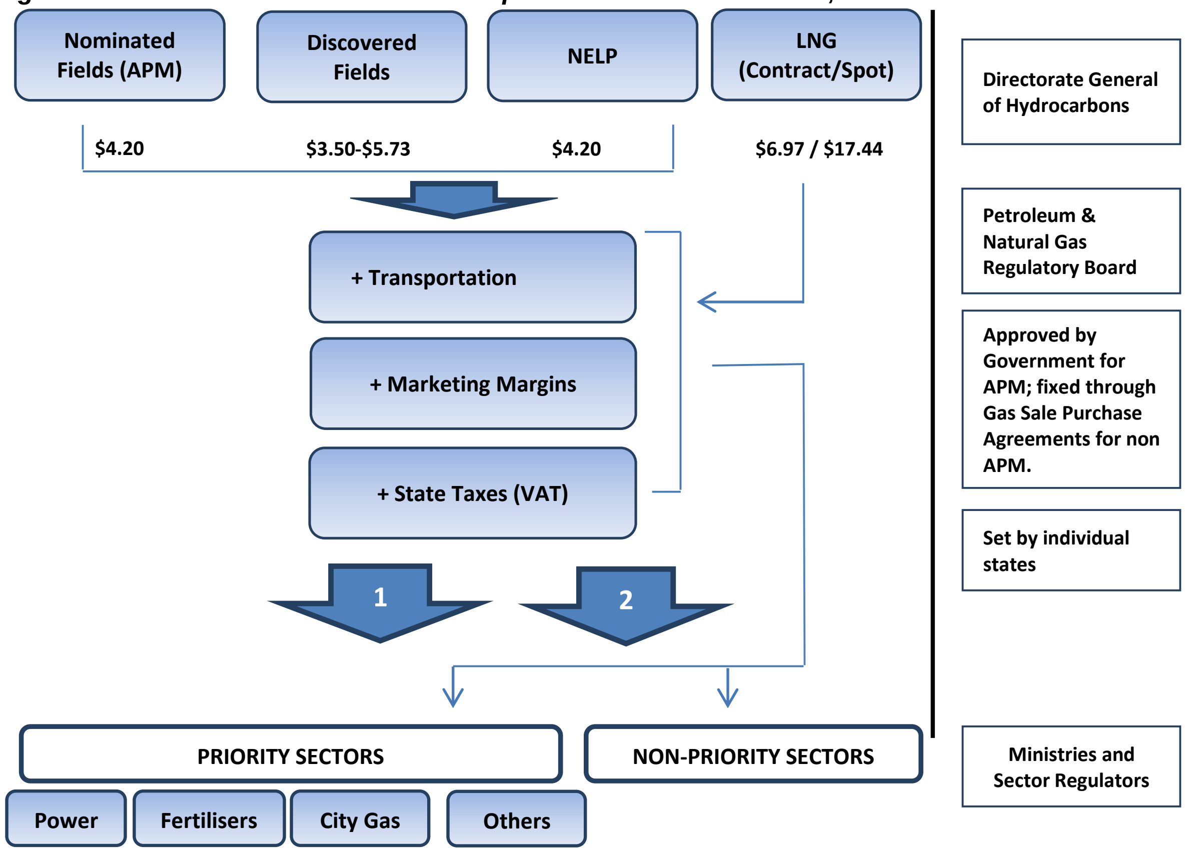
[10] In the fiscal literature, 'carried interest' implies that the NOC is 'carried' through the exploration phase by the international (or domestic) partner and only becomes a full working partner when a discovery is made.

[11] The LNG prices represented in this table do not take into account the recent fall in oil prices.

2.1 Pricing under the Nomination and Discovered Fields (Pre NELP) Regimes

Under the Nomination Regime (covering the period from Independence to the early 1990s, when exploration and production was carried out exclusively by the NOCs) prices were fixed by the government under its Administered Price Mechanism (APM) on a 'cost-plus' basis – or costs plus a regulated rate-of-return. There were some exceptions to this - gas sold to India's northeastern states, historically considered to be underdeveloped, was at a 40% discount on the APM rate, with the difference paid as a subsidy to the NOCs. Similarly, the government permitted gas from certain designated fields operated by the NOCs to be sold at non-APM prices or notional market prices ranging from $4.20 - $5.25/MMBtu. The price of gas produced under the Nomination regime was deliberately kept low, in order to subsidise certain industries, and by extension, their consumers.[13]

Figure 1: Structure of Indian Gas Prices *prior* to Gas Price Reform, 2014



Source: GoI (2014b); Rangarajan Committee (2012); Sen (2012); Jain (2011, p.111)

The Nomination regime was replaced by the Discovered Fields (Pre-NELP) regime in the early 1990s.[14] Prices under this were determined by Production Sharing Contracts between exploration companies and the government, and linked to an average of fuel oil prices over the previous 12 months, subject to a ceiling, which has been frequently revised (Corbeau, 2010). The Panna-Mukta-

[12] A model Revenue Sharing Contract (RSC) was circulated for comments in 2014. In January 2015, it was reported that the RSC would be adopted for marginal fields. See 'Revenue share model for oil explorers to debut for marginal fields' *Financial Express*, 5 January 2015. Available at http://www.financialexpress.com/article/economy/revenue-share-model-for-oil-explorers-to-debut-with-marginal-fields/26079/

[13] See Jain (2011), Corbeau (2010) and Joshi and Jung (2008) for detailed accounts of pricing strategy.

[14] No new acreage was offered under the old regime.

Tapti (PMT) and Ravva fields in northern India are important producing fields governed by this regime.[15]

In June 2010, the government increased the price of gas produced under the Nomination regime (or the APM) from \$1.79/MMBtu to \$4.20/MMBtu, to match the price of gas produced under the NELP regime. This decision was taken a few months after the start of gas production under the NELP – which was from the eastern offshore 'KG-D6' block operated by Reliance Industries Limited. This decision effectively doubled the price of APM gas, benefitting the NOCs which had struggled to break even under the old price. In November 2014, the price was again raised, based on a new formula (discussed in Section 2.5).

2.2 Pricing under the NELP Regime[16]

The NELP was launched in 1999 as India's liberalised upstream fiscal regime for hydrocarbons exploration and production, based on a Production Sharing Contract between exploration companies and the federal government. The gas price under NELP had to be determined by producers through a 'price discovery' process.[17] Once determined, the price had to be approved by the government. Following this approval, it became the 'uniform' price for NELP gas (excluding transportation charges, margins and state taxes) sold to all consuming sectors within the country.

Although no specific guidelines were issued on price discovery, the government published suggestions from a 2006 consultation on gas pricing, essentially leaving the process up to the producer. These included 'market determination' through a linkage to traded fuels in the formula, and a competitive bidding process for determining the price. Each instance of pricing approved under NELP was to be reviewed every 5 years.

The very first instance of gas pricing under NELP was for its first (and thus far, only) producing block, KG-D6 – operated by Reliance Industries Limited (Reliance). The formula for this was proposed by Reliance, the producer, and was approved by the Government with some revisions[18]: $SP = \$2.5 + (CP - 25)^{0.15} + C$.

SP represented the selling price (in \$/MMBtu), \$2.5 was a constant representing the base price of gas, and CP was the lagged price of Brent Crude, subject to a floor and a ceiling. C was a constant representing the outcome of bids (presumably as a proxy for demand) invited from consuming sectors in the original discovery exercise, which was later set to zero by the Government.[19] The power 0.15 gave rise to an S-curve with relative inelasticity at the upper and lower ends, meant to work in favour of buyers or sellers, respectively - it has been argued that the curve worked asymmetrically.[20] When approving the formula, the Government set the ceiling and floor for Brent at \$60 and \$25. Brent breached the \$60 ceiling soon after the adoption of the formula, and subsequently reached twice that level, which rendered the formula outdated.[21] The resulting price of \$4.20/MMBtu was adopted in 2009 for a 5 year period, and was meant to be reviewed in April 2014. A new formula for the pricing of domestic gas was adopted in November 2014 (discussed in Section 2.5) – however, this price will only become applicable to NELP gas when price clauses for Production Sharing Contracts come up for review.

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[15] All gas produced from the PMT and Ravva fields is sold to the gas marketing company GAIL. A percentage of this is then sold onward to the power and fertilisers sectors at the APM rate, with GAIL compensated for the difference through the government budget (Rangarajan Committee, 2012)

[16] A detailed analysis of the NELP gas pricing formula is provided in Jain (2011).

[17] Jain (2011) provides a description of this process.

[18] Jain (2011, p.116)

[19] Bids were received only from two sectors: power and fertilisers (Jain, 2011, p.116).

[20] Jain (2011, p.116); Jain and Sen (2011, p.41)

[21] Jain (2011, p.116)

Although prices under the NELP were meant to be market determined, they have frequently been subject to implicit government intervention. Jain (2011, pp.85-109) discusses how, through a series of amendments to the NELP Production Sharing Contract, policymakers attempted to achieve conflicting objectives: permitting gas producers the 'freedom to market' their gas, but subjecting them to the Government's 'Gas Utilisation Policy' which prioritised the power and fertilisers sectors amongst the buyers of NELP gas.

2.3 Pricing of LNG Imports

India began importing LNG in 2004. The prices for companies which purchase and market LNG (Petronet LNG and GAIL) are determined either by contracts or by the spot market. The government has occasionally pooled spot and contracted LNG to achieve a lower 'average' price for rationing gas to priority sectors to make up the shortfall of domestic gas.[22]

Under India's first long term contract, RasGas of Qatar agreed to supply 5 mtpa of LNG from 2004, at a contracted price of $2.53/MMBtu for 5 years, with a further 2.5 mtpa from January 2010. The period of fixed prices ended in 2009, and a 5 year transition then began to a 100 % linkage with crude oil.[23] The formula agreed between Petronet LNG Limited and RasGas was: P_o*JCC_t/$15

P_o was $1.90/MMBtu, JCC_t was the 12 month average of the JCC price and *t* referred to the month in which the price calculation was carried out. The term JCC_t in the formula was subject to a ceiling and a floor, which were:

Ceiling: $[(60-N) * 20+ (N*A_{60})]/60+4$

Floor: $[(60-N)*20 + (N*A_{60})]/60-4$

Where, N =1 for January 2009, and increased by 1 every month thereafter until December 2013, after which it remained 60, and A_{60} = 60 months' average of the JCC price.

Added to the FOB price/MMBtu were shipping ($0.30), insurance ($0.0017), customs duty ($0.50) and regasification ($0.60) resulting in a total FOB price of $10.44/MMBtu. In comparison, contract prices in the Pacific Basin were at the time in the range of $12-$18/MMBtu. In April 2012, India rejected an offer from Qatar to supply an additional 5 mtpa at prevailing Brent Crude prices with a slope of 14.5 %.[24]

In 2012, Petronet LNG Limited signed a contract with Exxon Mobil to import 1.44 mtpa of LNG from the Gorgon project in Australia, beginning in 2015. The price agreed was 14.5 % of JCC. At a JCC price of $80/barrel, and added costs for shipping ($0.75), insurance ($0.0017), customs duty ($0.636) and regasification ($0.64) this results in a total price of $13.63/MMbtu.

A break from JCC-linked pricing occurred when a contract was signed between GAIL and Cheniere Energy (USA), for the import of 3.5 mtpa from Cheniere's Sabine Pass terminal beginning in 2017, for 20 years. The pricing formula comprised 115 % of Henry Hub plus a fixed capacity charge of $3/MMBtu. Thus, for Henry Hub at $3.71 (the average over 2013), the delivered price of LNG to India, assuming a shipping cost of $2 would be around $9/MMBtu (plus regasification costs of around $0.50/MMBtu). In 2012, GAIL was reported to be in negotiations to sign a second Henry Hub linked contract with Macquarie Energy for LNG supplies from Texas.[25]

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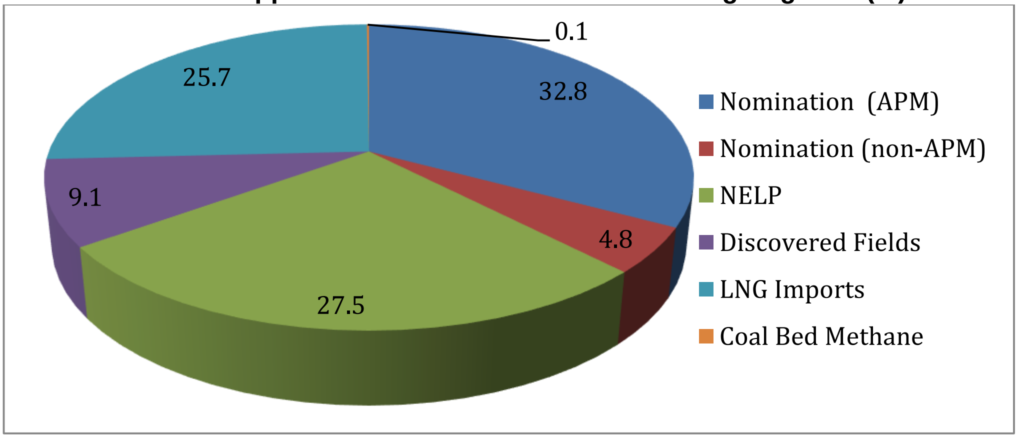
[22] Jain (2011, p.156). This was carried out for the Dabhol power plant, and for city gas distribution.
[23] Flower (2010, pp.367-368)
[24] At $110/barrel, this was $15.96/MMBtu. See 'India Rejects Qatar Price for LNG' *The Economic Times,* 2 April 2012. Available at http://economictimes.indiatimes.com/news/news-by-industry/energy/oil-gas/india-rejects-qatar-price-for-lng/articleshow/12504877.cms
[25] (WGI, 2012). These negotiations have not yet resulted in a firm outcome.

In addition to the systems of pricing above, India produces a small amount of coal bed methane, for which prices have been subject to government approval.

Figure 2 shows approximate amounts of gas supplied under the different upstream fiscal regimes and LNG imports in 2012, totalling roughly 60 Bcm. The proportion of NELP gas has since decreased due to the decline in production from the KG-D6 block.

Figure 2: Domestic Gas Supplied under Different Fiscal & Pricing Regimes (%)



Source: Rangarajan Committee (2012)

2.4 The 2013 Reform Proposal (Rangarajan Committee)

The 2013 proposal to reform domestic gas prices was prompted by multiple drivers, the most prominent of which has been the controversy over declining production levels. India's domestic gas pricing regime, along with its fiscal regime for exploration, came under scrutiny after production from what had originally been referred to as a 'game changer' – the KG-D6 gas discovery in the eastern offshore Krishna Godavari basin operated by Reliance Industries Limited – began dramatically declining from 2011 onwards.[26] This prompted questions over whether the upstream regime was effective both in terms of incentivising exploration and production, and in the administration of Production Sharing Contracts. In August 2011, India's National Auditor published a report alleging that large amounts of revenue had potentially been lost to the exchequer due to ad hoc extensions and policy relaxations granted by the upstream regulator to exploration companies.

The pricing formula for NELP gas was due to be reviewed on 1 April 2014. In connection with this and following on from the report of the National Auditor, in April 2012, the Indian government appointed the Rangarajan Committee to review both the upstream fiscal regime and the system of gas pricing, and to make recommendations for reform. The Committee published its recommendations in December 2012, and they were officially approved by the government in June 2013.

Based on these recommendations, the price of gas to domestic producers from 1 April 2014 (prior to its suspension by the Election Commission) was to be set on the basis of the 12 month trailing average of:

a) the volume weighted average of netback prices to producers at the exporting country wellhead (for all Indian LNG imports), and,

[26] Reserves were revised downwards from 10 tcf to between 3-5 tcf. By May 2014, it was achieving roughly 14 MMscmd, or less than a third of its targeted peak production of 80 MMscmd. This is discussed further in Section 4.1.

b) the volume weighted average prices of gas traded in three major markets – US Henry Hub, UK National Balancing Point and the netback price of Japan Customs-cleared Crude (JCC).

The new pricing formula was meant to be applicable to domestically produced natural gas, coal bed methane and shale gas. It was meant to be applied with immediate effect to gas produced by the NOCs under the Nomination regime, but for all other gas, it was meant to become applicable when contractual price clauses came up for review – in the case of KG-D6 gas, this would have been on 1 April 2014. The formula was to be revised on a quarterly basis until 2019, by which time the Committee hoped the Indian gas market would have developed sufficiently to allow price-setting on the basis of gas-on-gas competition.

The rationale underlying the pricing formula proposed by the Rangarajan Committee was predicated on the 'arm's length' pricing principle outlined in India's model Production Sharing Contract. The Rangarajan Committee's recommendations stated that the NELP regime represented a 'conscious move away from below-cost pricing and cost-of-service pricing'.

A continuation of oil price indexation was rejected in the recommendations, on the basis that gas did not substitute for oil in India's two largest gas consuming sectors: fertilisers and power. In fertilisers, due to a conscious policy of converting all naphtha-based urea manufacturing plants to gas-based plants, 81% of urea manufacturing capacity is gas-based, with 9% based on naphtha and 10% on fuel oil.[27] Similarly, in power, gas substitutes for coal, which forms roughly 70% of installed capacity.

In addition to the 'arm's length' principle and gas-on-gas competition, the formula appeared to be based partly on elements of opportunity cost. This was evident in its two components (a) and (b) described above.

The first component - 'the volume weighted average of netback prices' for Indian LNG imports - was linked with the concept of 'import parity pricing', previously used to price petroleum products in India.[28] The Committee's recommendations noted that for gas, 'extraneous costs' (taken broadly to include liquefaction and transportation) had no relevance to domestic producers. It proposed a formula for the calculation of netback prices:

$N = A – B – C$

A was the imported LNG price on a netback FOB basis, B referred to liquefaction costs at the loading port; and C comprised transportation and treatment costs from the wellhead to the liquefaction plant.

The volume weighted average of netback prices to producers at the exporting country wellhead (for Indian LNG imports) was therefore: $P_{IAV} = (N_1*V_1+…N_n*V_n) / (V_1+….V_n)$

Where N represented producer netbacks, and V, volumes.

The second component of the new pricing formula, 'the volume weighted average prices of gas traded in three major markets', was meant to represent 'what global gas players get from their investments'.[29] This component was to be calculated by the formula:

$P_{WAV} = (A_1*P_{HH} + A_2*P_{NBP} + A_3*P_{JAV}) / (A_1 + A_2 + A_3)$

P_{WAV} was the weighted average prices to producers in global markets; A_1 was the total volume consumed in North America at average Henry Hub prices on a yearly basis; P_{HH} was the annual average Henry Hub price for the relevant year; A_2 was the volume consumed through hubs in Europe; P_{NBP} was the annual average of daily prices on the NBP for the relevant year; A_3 was the volume imported by Japan in the relevant year; and, P_{JAV} was the yearly weighted average producers'

[27] Rangarajan Committee (2012)
[28] Based on what domestic producers would receive for their products in the international market.
[29] Rangarajan Committee (2012)

netback price of gas in Japan for the relevant year (weighted by the total volume of long term and spot imports) calculated by the formula: netback FOB price – liquefaction cost – transportation cost.

The final domestic gas price under this proposal therefore represented an average of the two averages above, shown by the formula:

$P_{AV} = (P_{IAV} + P_{WAV}) /2$

The Committee also estimated an average liquefaction cost of $2.50/MMbtu[30] and an average transportation cost of $0.50/MMbtu while calculating the producer netback.

Had the formula become applicable on 1 April 2014, the gas price would have risen to $8.40/MMBtu in April 2014.

However, in March 2014, India's Election Commission directed the government at the time to postpone the implementation of gas price reform until after the April general election had been completed, on the basis that new policy changes in the run up to the elections would have violated the Election Code of Conduct. The reform was subsequently put off until June 2014; however, the new government that took office in June 2014 instituted a fresh review of gas pricing and postponed the decision by a further three months.

2.5 The 2014 Gas Price Reform

On 18 October 2014, India's new government published its decision on gas pricing reform[31], based on modifications to the Rangarajan formula. Two price benchmarks were removed from the formula – the volume weighted average of netback prices to producers at the exporting country wellhead (for Indian LNG imports), and the volume weighted average producers' netback price of gas in Japan. Instead, two new components were introduced in the formula – the Alberta (gas) Reference price weighted by the volume of Canadian gas consumption, and the Russian domestic gas price weighted by the total annual volume of natural gas consumed in Russia.

The new formula is as follows:

$$Domestic\ Gas\ Price = \frac{V_{HH} * P_{HH} + V_{AC} * P_{AC} + V_{NBP} * P_{NBP} + V_R * P_R}{V_{HH} + V_{AC} + V_{NBP} + V_R}$$

Where:

- V_{HH} is the total annual volume of natural gas consumed in the USA and Mexico.
- V_{AC} is the total annual volume of natural gas consumed in Canada.
- V_{NBP} is the total annual volume of natural gas consumed in the EU and FSU, *excluding* Russia.
- V_R is the total annual volume of natural gas consumed in Russia.
- P_{HH} and P_{NBP} are the annual average of daily prices at Henry Hub (HH) and National Balancing Point (NBP), respectively, less $0.50/MMBtu towards transportation and treatment charges.

[30] $3.50 for deliveries starting after 2010.

[31] See 'Revision of Domestic Gas Prices', 18 October 2014, Press Information Bureau, Government of India. Available at http://pib.nic.in/newsite/PrintRelease.aspx?relid=110696

- P_{AC} and P_R are the annual average of monthly prices at the Alberta 'Hub' and in Russia, respectively, less $0.50/MMBtu towards transportation and treatment charges.

Under the new reforms:

- Prices will be reviewed every 6 months, based on trailing price and volume data for the previous four quarters with a lag of one quarter. Therefore, the first case of pricing under the new reform (applicable from 1 November) was based on prices prevailing between 1 July and 30 June 2013 and was revised on 1 April 2015.

- The price is set on the basis of Gross Calorific Value (rather than Net Calorific Value under the previous system of gas pricing). Based on the formula, the price of domestic gas between 1 November and 31 March 2015 was initially reported to have risen to $5.61/MMBtu from $4.20/MMBtu[32], but an official government notification released on 26 October 2014 set the price at $5.05/MMBtu.[33] The review on 1 April 2015 set the price at $4.66/MMBtu for the six month period to 30 September 2015.

- For deep water and ultra-deepwater production, a premium could be added onto the new price.[34] At the time of writing this had yet to be announced.

The new gas price is applicable to all gas produced from Nomination Regime (legacy) fields given to the NOCs - ONGC and Oil India Limited – new NELP blocks, such Pre-NELP blocks where the Production Sharing Contract (PSC) provides for Government approval of gas prices, and Coal Bed Methane blocks. The new gas price does not apply to:

- Small and isolated fields under the Nomination Regime (legacy) blocks of the NOCs.
- Instances where prices have been fixed contractually for a certain period of time, till the end of such a period.
- Instances where the PSC provides a specific formula for natural gas price indexation or fixation.
- Pre-NELP regime blocks where government approval is not required under the Production Sharing Contract (PSC).

The new gas price will not apply to Reliance/BP 'KG-D6' gas until arbitration is completed. The government in its original announcement suggested that the difference between the new price and the 'old' price ($4.20/MMBtu) could be credited to a 'gas pool account' managed by the state-owned gas marketing company GAIL. Whether the amount collected would then be paid out to the contractors of KG-D6 would depend on the outcome of arbitration. The immediate beneficiaries of the new gas price are therefore the NOCs.[35] Figure 3 depicts domestic gas prices for India over time alongside the

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[32] See 'Gas price fixed at $5.61/MMBtu, diesel cut by Rs. 3.37/l' *Moneycontrol*, 18 October 2014. Available at http://www.moneycontrol.com/news/economy/gas-price-fixed-at-36561mmbtu-diesel-cut-by-rs-337l_1207111.html

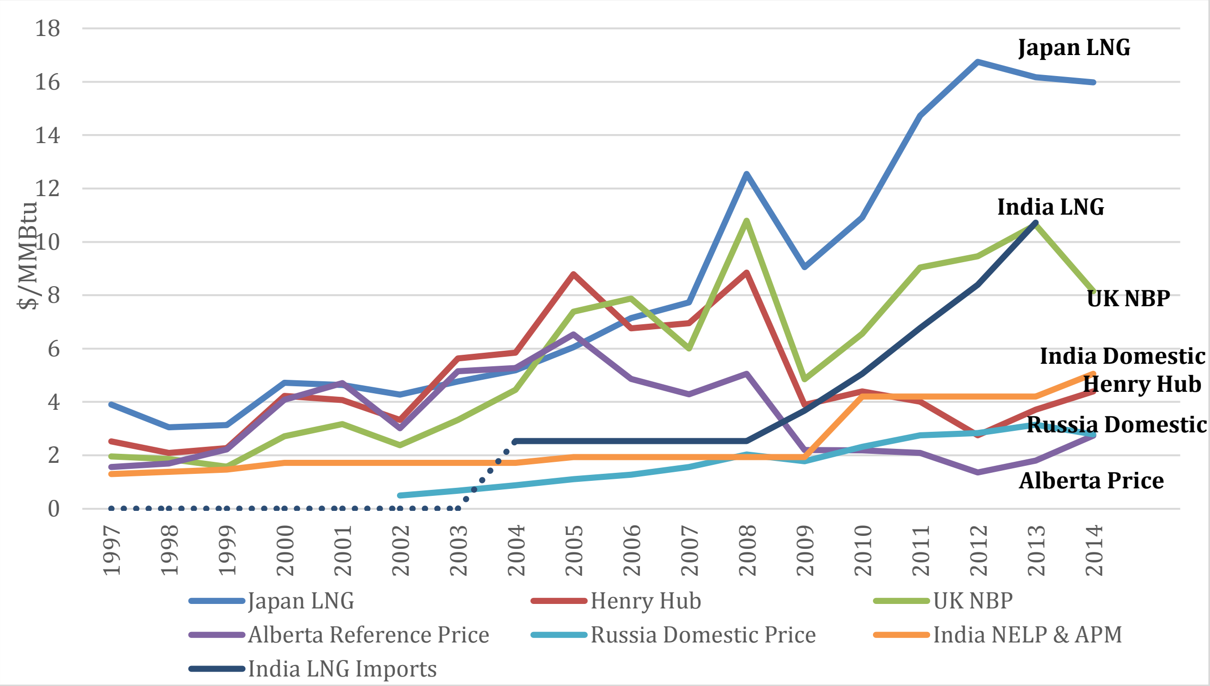
[33] See 'Domestic Gas Price, November, 2014-March, 2015', Petroleum Planning and Analysis Cell, 26 October 2014. Available at http://ppac.org.in/WriteReadData/CMS/201501270451563110729NG_PriceNotificationNovember14-March2015.pdf

[34] In January 2015, a group of private companies proposed that the formula for calculating the premium be linked to an annual average price of fuel oil, unsubsidised LPG, naphtha and distillates in the domestic market. The proposal suggested setting the premium at 70% of this annual average price to begin with, gradually moving to 90% of this price over a 3 to 5 year period. See 'Private oil companies suggest gas price at $5.7-7.4 per unit' *Indian Express,* 13 January 2015. http://indianexpress.com/article/business/economy/private-oil-companies-suggest-gas-price-at-5-7-7-4-per-unit/

[35] We discuss in Section 4 how NOCs have struggled to break even because of low domestic gas prices, how most of their production has plateaued, and how they reportedly require prices in excess of $6-$8/MMBtu in order to bring marginal fields into production. However, NOCs' revenues are diverted by the central government to finance the cost of subsidies. This leaves fewer revenues for reinvestment into exploration – thus constraining NOCs' capital investment budgets.

international prices used as benchmarks in the new formula, as well as the previous (Rangarajan Committee) formula.

Figure 3: India Gas Price versus International Gas Prices, 1997-2014



Source: BP (2014); GoI (2013); Gazprom IFRS Financial Reports (2002-14); Alberta Energy (1997-2014)[36]

2.5.1. Analysis – Is the new formula relevant to India's Gas Market?

The literature on gas pricing distinguishes between the concepts of *price level* and *price formation*, and attributes the dilemmas faced by developing economies in setting gas prices to a focus on the level as opposed to the formation mechanism.[37] In the pursuit of distributional objectives, the literature argues in favour of allowing prices to be set through price formation mechanisms, and providing subsidies directly to eligible consumers. India is currently transitioning to a system of 'direct cash transfers' in an attempted reform of subsidy deliveries.

Nevertheless, India's gas price reforms (including the Rangarajan proposals) have focused on *managing the price level*, rather than finding a logical, market-based *mechanism for price formation*. This is reflected in some of the mixed rationale expressed in the report of the Committee tasked with reviewing the Rangarajan formula. [38] It dropped Japan LNG import prices (and Indian LNG import prices), amongst other reasons, on the basis that they were oil-indexed on term contracts, and in the case of Japan LNG, 'the most expensive in the world'. Similarly, it included Canadian (Alberta gas reference) prices for the proportion of North American gas traded in Canada (which it approximates at 11-12%) as they are 'approx. 20% lower than the Henry Hub price'. The report also stated that 'oil-

[36] Nominal prices. Russian average domestic price converted from Roubles/mcm to $/MMBtu using historical exchange rates from http://www.oanda.com/currency/historical-rates/ and the conversion $1/MMBtu=$36.2/mcm from Stern (2012). 2014 average price for Henry Hub obtained from the EIA, and for Japan LNG obtained from http://ycharts.com/indicators/japan_liquefied_natural_gas_import_price . 2014 data for average India LNG import price unavailable. UK NBP price for 2015 from Platts European Gas Daily Monthly Averages supplement. Russia average domestic price data for 1997-2001 unavailable.

[37] Rogers and Stern (2014); Stern (2012)

[38] GoI (2014b)

indexed LNG term prices do not have much relevance for domestic producers' price, as pricing of about 90% of all global domestic consumption of gas is based either on Gas-on-Gas competition or is under regulated price regimes'. While a move away from oil-indexed pricing is supported by the literature[39] this reasoning runs contradictory to the inclusion in the formula of Russian domestic gas prices for the proportion of European gas consumption representing Russia, where there has been a 'two-tier' market, with Gazprom selling at a low, regulated price and independent (non-state owned) gas companies typically selling at (until recently) a premium to the regulated price.[40]

Russian domestic gas prices are not market-based – they are regulated by the government and are arguably linked to oil prices. In 2006, regulated Russian domestic gas prices began to be raised each year towards European netback levels (oil-linked price of Russian gas to Europe on long term contracts based on take-or-pay commitment, minus transportation costs and export taxes) related to a world oil price of around $55/barrel.[41] The increase in domestic prices was introduced as part of reforms aimed at equalising Russia's domestic gas price with its European export price by 2011 (which was not achieved), in the pursuit of various commercial and political objectives. These included the need at the time for Gazprom to monetise its more expensive (higher marginal cost) non-Soviet era fields, to achieve greater efficiency of energy use in the Russian economy, and to meet requirements for WTO membership.[42] This was accompanied by the establishment of a Gas Exchange as a 'building block' for price liberalisation, which initially aimed at allowing the trading of 10 Bcm/year (increased to 15 Bcm in 2008) – representing around 2% of Russia's total domestic gas consumption in 2006.[43] Trading on the Gas Exchange was halted in 2009, and since then there continues to be a debate over whether the Exchange should represent a purely physical market, or additionally, a futures market, with a draft resolution on a new trading system yet to be implemented.[44]

The process of reforms has since slowed down, and potentially changed in scope, as the relevance of the 'netback parity target' was called into question following a slowdown in the Russian economy (including falling industrial demand for gas) around 2013. This has led to a unique situation where the independents are now able to sell at a *discount* to the regulated price in order to maintain (or capture) market share, and to cherry-pick their customers, leaving Gazprom to sell to a large proportion of non-paying consumers (Municipality and Residential segment), at the (currently) higher regulated price.[45] These developments indicate that some sort of competition is beginning to emerge in the Russian domestic gas sector, not just based on price but also based on sellers' and consumers' confidence in the availability of long-term transport arrangements through third-party access to the trunk pipelines.[46] But as the sector continues to be regulated, and with the potential abandonment of the netback parity target, the future evolution of Russia's domestic gas market will be strongly influenced by its economic situation and political objectives. Henderson, Pirani and Yafimava (2014) argue that Russian gas demand growth has almost come to a halt and will remain slow for the remainder of this decade due to the nature of the Russian economic recovery and a slowdown in population growth amongst other factors, and could even be zero or negative. This indicates that domestic gas price *levels* could also remain low.

Similarly, the 'hub' prices included in the formula are underpinned by the market dynamics of the regions that they represent, which are changeable. The inclusion of Henry Hub may be indicative of what Rogers and Stern (2014) argue is an 'Asian enthusiasm' for Henry Hub as an alternative to Japan Customs Cleared (JCC), and it is subject to two caveats. First, it risks confusing price level with price formation - that is, embracing a mechanism because it presently gives a lower purchase price

[39] Rogers and Stern (2014)
[40] Henderson, Pirani and Yafimava (2014; 2012)
[41] Henderson, Pirani and Yafimava (2014; 2012)
[42] Henderson, Pirani and Yafimava (2014; 2012)
[43] Henderson, Pirani and Yafimava (2014; 2012)
[44] Henderson, Pirani and Yafimava (2014; 2012)
[45] Henderson, Pirani and Yafimava (2014; 2012)
[46] Henderson, Pirani and Yafimava (2014; 2012)

compared with JCC-linked long term LNG contracts; and second, Henry Hub represents the fundamentals for the North American market, which are likely to change independent of Asian market fundamentals.[47] North American gas exports would be likely to raise Henry Hub prices, and in any case, it has been argued that very low Henry Hub prices are unsustainable in the long term as exploration companies will find it unprofitable to continue drilling. There are however different estimates as to by how much prices may increase[48] and arguably the jury is still out on whether they could increase to levels around or higher than JCC, or whether there are automatic stabilisers in the system.[49]

Similarly, NBP is underpinned by the fundamentals of the UK (and increasingly, European) market which it has been argued currently represents an oligopolistic rather than a perfectly competitive market structure.[50] Collectively, Henry Hub and NBP are viewed as more 'volatile' than other contractual mechanisms, and subject to the dynamics of the geographies that they represent. In early 2015, UK NBP prices were briefly reported to be trading at a $1.20/MMBtu premium to spot Asian LNG prices, in a reversal of the trend seen at the same time last year[51] – this reflects the changeability of regional dynamics. The inclusion of the Alberta gas reference price is again, an indication of the focus on *price level* – recent literature looking at relationships among eight North American natural gas spot market prices (including Henry Hub and the AECO Alberta 'hub') indicate that the Canadian and US natural gas market is a single highly integrated market, despite some regional differences.[52] This suggests that Henry Hub is largely representative of North American dynamics.

These observations suggest that the new gas price formula is predicated around managing the price level, rather than establishing a logical market-oriented basis for price formation. Conversely, it also shows how the argument cuts both ways – gas producers in India arguing for the deregulation of gas prices and their pegging to international benchmarks in order to obtain higher prices would have been equally affected financially, had the Rangarajan formula been adopted, as the recent decline in international oil prices has led to falling Japan LNG prices. Nevertheless, the decline in oil prices from June 2014 to early 2015 combined with the lag in India's gas pricing formula suggest that India's domestic gas price could fall further in 2015/16. This may have implications for upstream production (discussed in Section 4). It is clear that the main element lacking in India's pricing formula is some reflection of India's gas market dynamics (as nascent as they are).

The implications of pricing reform can be better understood after an overview of India's gas sector and the structure of demand.

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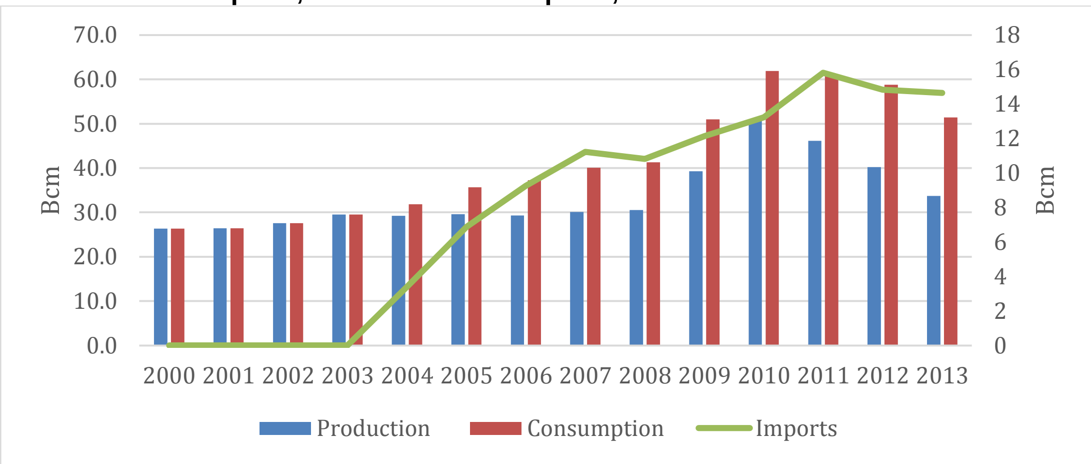
[47] Rogers and Stern (2014)
[48] Foss (2011); Rogers and Stern (2014)
[49] Primarily the dynamics of the US economy – for instance, if the prices of Henry Hub increase beyond a certain threshold this would prompt more drilling and greater supply. Alternatively, the US could regulate the granting of export licenses for LNG.
[50] Rogers and Stern (2014)
[51] See 'Europe Overtakes Asia as LNG's Hottest Market', *Oilprice.com*, 25 February 2015. http://oilprice.com/Energy/Natural-Gas/Europe-Overtakes-Asia-As-LNGs-Hottest-Market.html
[52] Park et al (2010)

3. India's Gas Sector – An Overview

Gas has a relatively recent history in India, with the first domestic discoveries made by its NOCs in the 1970s.[53] Gas forms roughly 7% of India's primary energy consumption, compared with 43% coal, 22% oil and the remaining 28% a mix of other sources including renewables. Figure 4 shows gas consumption and production from 2000-2013 measured on the left vertical axis, and imports (which began in 2004) measured on the right vertical axis.

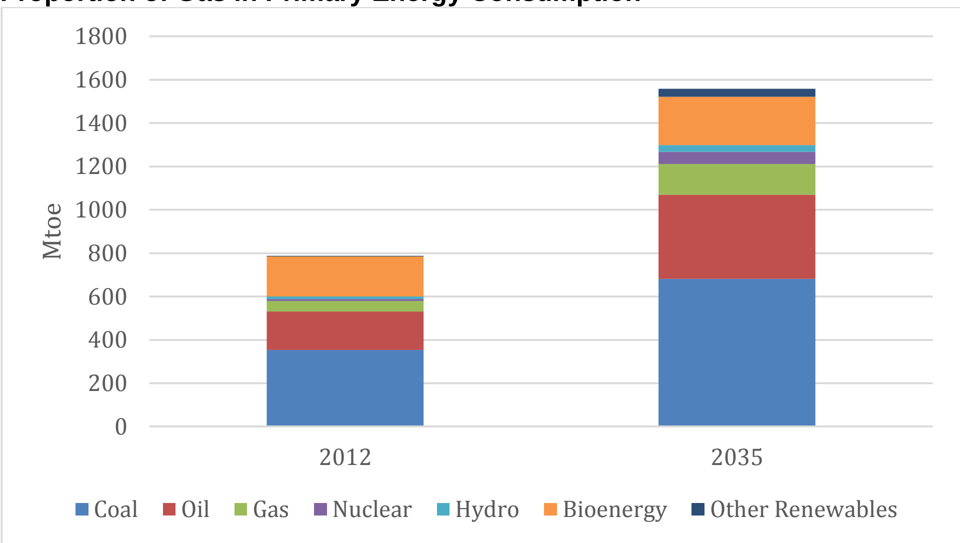
Figure 4: Gas Consumption, Production and Imports, 2000-2013



Source: BP (2014); PPAC (2014)

Figure 5, the IEA 2014 New Policies Scenario shows that the proportion of gas is likely to grow by the year 2035, but not by enough to displace either coal or oil.

Figure 5: Proportion of Gas in Primary Energy Consumption



Source: IEA (2014)

Despite the relatively small existing and forecast proportions of gas in primary energy consumption, Indian policymakers have tended to be very optimistic with regard to the potential for gas as a fuel

[53] Jain (2011) provides a detailed review of the development of India's gas sector.

that could displace the use of coal and petroleum products in electricity, cooking and transportation. However, given that the use of these substitutes is entrenched in the economy, supported by controlled pricing and subsidies, there is considerable ambiguity as to how and where these potential markets for gas could materialise.

3.1 Projections of Demand and Domestic Supply

The complexity of the Indian gas sector is reflected in the availability of varied projections of supply and demand, underpinned by different assumptions. These projections can be broadly grouped into two categories: official government forecasts and projections carried out by external agencies.

Official government forecasts tend to be carried out within a 'central planning' framework – this is described in Jain (2011). Typically, forecasting by central planners begins with a quantity based on likely domestic production. This quantity is then allocated amongst different uses, and then priced. In the event of a shortage, the price is unlikely to be revised, but the quantity may be increased through imports. Planned forecasts are therefore based on key assumptions about availability. In the official supply forecasts, it is assumed that forecast supply will be utilised. Similarly, in official demand forecasts, it is assumed that prices will be set at levels that allow gas to compete with alternative fuels, and that the infrastructure networks necessary for delivery will exist.[54]

Official forecasts appear to reflect this thinking in their reporting of demand and supply. First, 'demand' refers to the 'use' of gas, rather than depicting a position brought about through the price system. And second, supply and demand are sometimes reported as one number.[55]

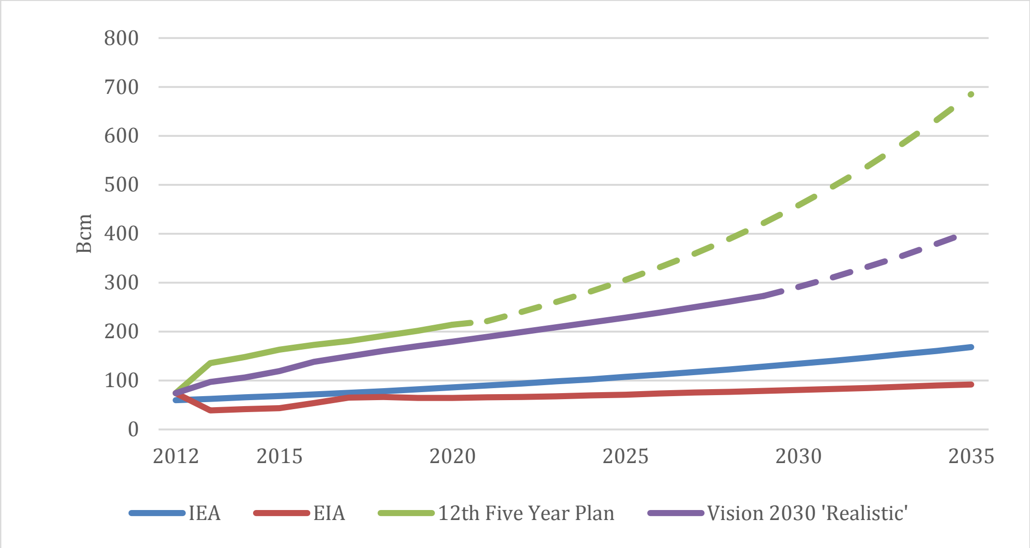
It is reasonable to conclude that official government forecasts tend to be overly optimistic, whereas projections by other agencies are likely to include cautious assumptions. Figures 6 and 7 show the heterogeneity of projections of demand and domestic supply up to 2035 based on four sources.

These include:

- The IEA 2014 World Energy Outlook New Policies Scenario for India[56]
- The EIA 2014 International Energy Outlook Reference Case Scenario[57]
- The Government of India's 12th Five Year Plan[58]
- The Indian Petroleum and Natural Gas Regulatory Board's projections, based on adjustments to the 12th Five Year Plan projections to obtain more 'realistic' forecasts, in a document titled ' Vision 2030'[59]

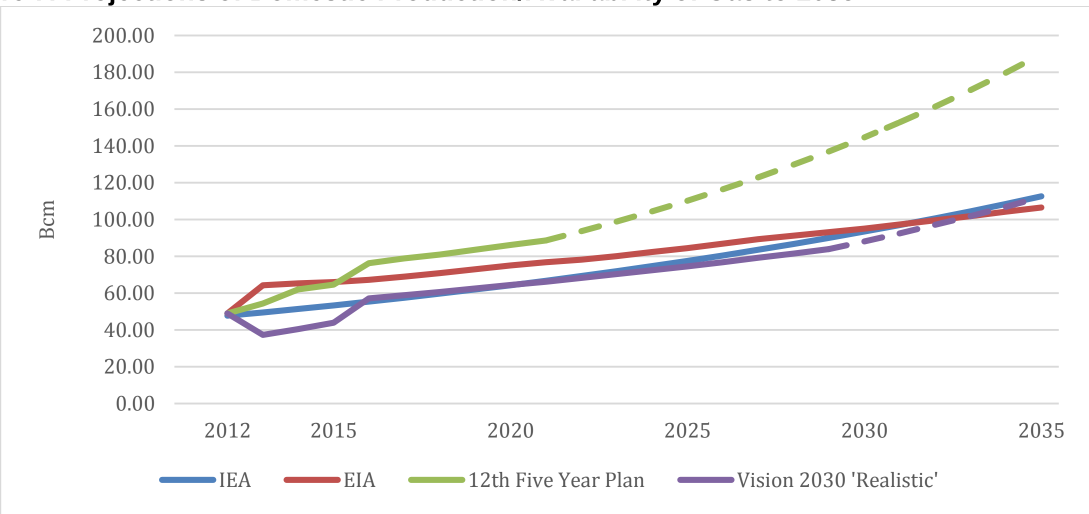
[54] Jain and Sen (2011); Jain (2011)
[55] Jain and Sen (2011); Jain (2011)
[56] For details see http://www.iea.org/publications/scenariosandprojections/
[57] For details see http://www.eia.gov/forecasts/aeo/
[58] For details see http://planningcommission.nic.in/plans/planrel/fiveyr/welcome.html
[59] For details see http://planningcommission.nic.in/plans/planrel/fiveyr/welcome.html

Figure 6: Projections of Demand/Use of Gas to 2035



Source: IEA (2014); EIA (2013); GoI (2012a); PNGRB (2013); Author's estimates

Figure 7: Projections of Domestic Production/Availability of Gas to 2035



Source: IEA (2014); EIA (2013); GoI (2012a); PNGRB (2013); Author's estimates[60]

Each of these projections is based on a set of assumptions: for instance, the IEA 2014 New Policies Scenario takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse-gas emissions and plans to phase out fossil-energy subsidies, even if the measures to implement these commitments have yet to be identified or announced. Similar sets of assumptions apply for the other three projections.[61]

Production was about 34 Bcm in 2013, and total consumption was roughly 48 Bcm. Figure 7 shows that there is greater consensus on supply forecasts with the majority converging within a range of 100

[60] Compound Average Annual Growth Rates (CAAGR) for each forecast were used to obtain data up to 2035 for the 12th Five Plan and Vision 2030 'Realistic' documents which otherwise cover shorter time periods. The dotted lines on the graph indicate these extrapolations. The assumptions underpinning these growth rates can be found in the full published reports for each projection.

[61] Readers may refer to the full published reports for a detailed discussion of assumptions.

– 112 Bcm by 2035. Figure 6 however shows the divergence between various demand projections. Whilst the 'Vision 2030' forecast which adjusts official projections from the 12th Five Year Plan places potential demand in 2035 at nearly 400 Bcm, the IEA and EIA forecasts place it within a more conservative range of 90-200 Bcm.

Table 2: Growth Rates Assumed in Projections

Forecast	Demand CAAGR (%)	Supply CAAGR (%)
IEA 2014 New Policies Scenario	4.6%	3.8%
EIA 2014 International Energy Outlook	3.4%	3.0%
Government of India 12th Five Year Plan	7.0%	5.0%
Indian Petroleum and Natural Gas Regulatory Board 'Vision 2030'	8.0%	6.0%

Source: IEA (2014); EIA (2013); GoI (2012); GoI (2013); Author's estimates

As stated earlier in this paper, this divergence in assessments of demand is primarily due to the lack of a clear price signal. The Indian gas sector is broadly characterised by two moving parts: one which has prices and quantities set by the Indian government, and another which utilises gas at market (LNG import) prices. There is also some overlap between the two, making the assessment of the two parts as separate markets very difficult. It is however possible to identify the drivers of demand within these two broad parts.

3.2 The Structure and Drivers of Demand

The structure of demand can be analysed starting with the different consuming sectors categorised in the government's 'Gas Utilisation Policy' – a policy which supports the rationing of domestically produced gas to certain 'priority' sectors before it is released for sale to the wider Indian market. Jain (2011) provides a detailed analysis of the development of this policy of rationing domestic gas, via the incorporation of specific clauses into the NELP Production Sharing Contract which requires all domestically produced gas to be subject to the government's Gas Utilisation Policy.

Table 3 below shows a two-tier structure for all domestically produced gas that is subject to the Gas Utilisation Policy. Gas is first released to Tier 1 consumers, and then to Tier 2 consumers. Column 3 shows the total percentage of domestic gas utilised by each Tier. Additionally, Column 4 shows the total percentage of LNG imports utilised by each Tier (although LNG imports are not within the ambit of the Gas Utilisation Policy). Tier 1 consumers comprise gas-based fertiliser plants, Liquefied Petroleum Gas (LPG) manufacturing plants[62], grid-connected gas fired power plants, and city gas for households (also known as Piped Natural Gas or PNG) and transportation (Compressed Natural Gas or CNG). Tier 2 consumers comprise steel, refineries and petrochemical plants, city gas for general industry and commerce, and all other consumers, include power plants that operate on a captive (self-generation) or merchant (generation for sale to utilities or third parties) basis.

[62] Roughly half of the LPG produced in India is extracted from natural gas.

Table 3: Structure of Demand for Domestically Produced Gas

Tier (1)	**Consumer Type and Priority Order (2)**	**% Domestic Consumption (3)**	**% LNG (4)**
Tier 1	1.Fertiliser Plants[63] 2.LPG Extraction Plants 3.Grid-Connected Power Plants 4.City Gas for Households & Transport Domestic Gas	86%	53%
Tier 2	1.Steel, Refineries & Petrochemical Plants 2.City Gas for Industrial & Commercial Consumers 3.Other Consumers, Captive & Merchant Power Plants, Feedstock or Fuel	10%	40%
Total		96%	93%

Source: BCG (2013); PNGRB (2013); Author

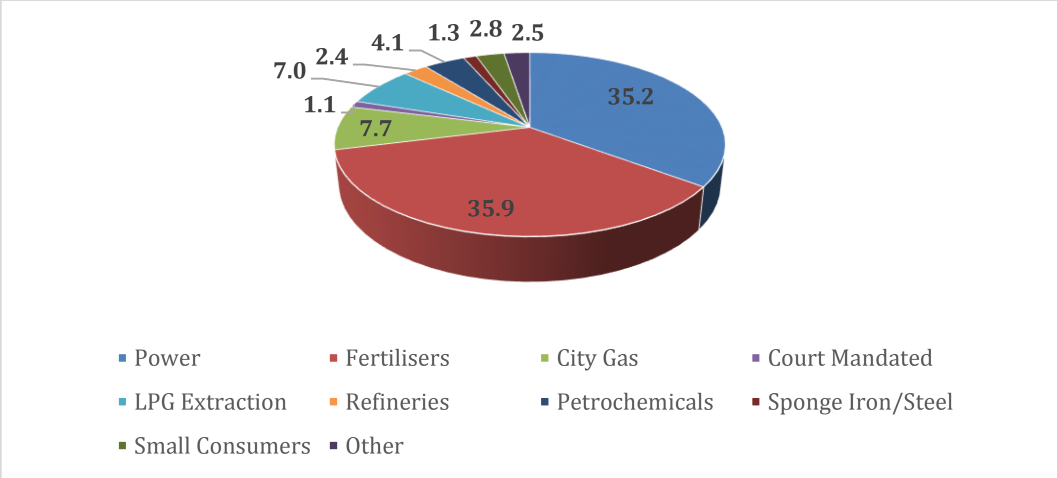
The table above accounts for 96% of domestic gas consumption and 93% of LNG imports. This is because there are two further 'special' consumer categories that do not quite fit into the structure above but are technically both part of Tier 1 demand, and have not been included in the table – they are (a) small consumers requiring less than 50,000 scm/d of gas, and (b) consumers to whom the courts have mandated the supply of gas.[64] Collectively, these two categories account for the remaining 4% of domestic consumption, and 7% of LNG imports.

In July 2014, soon after the election of the new government, the priority order under the Gas Utilisation Policy was changed – City Gas for households and transportation was moved to the top of the priority order under Tier 1. This, combined with the new government's ambitions to develop a 'national gas grid' could indicate a major shift in policy aimed at widening the consumer base for gas beyond its traditional fertiliser and power segments, as well as a major change in the dynamics of demand, which have arguably been set by fertilisers.

Figures 8 and 9 show estimates of the percentages of consumption by all consumer categories of domestic gas and LNG imports.

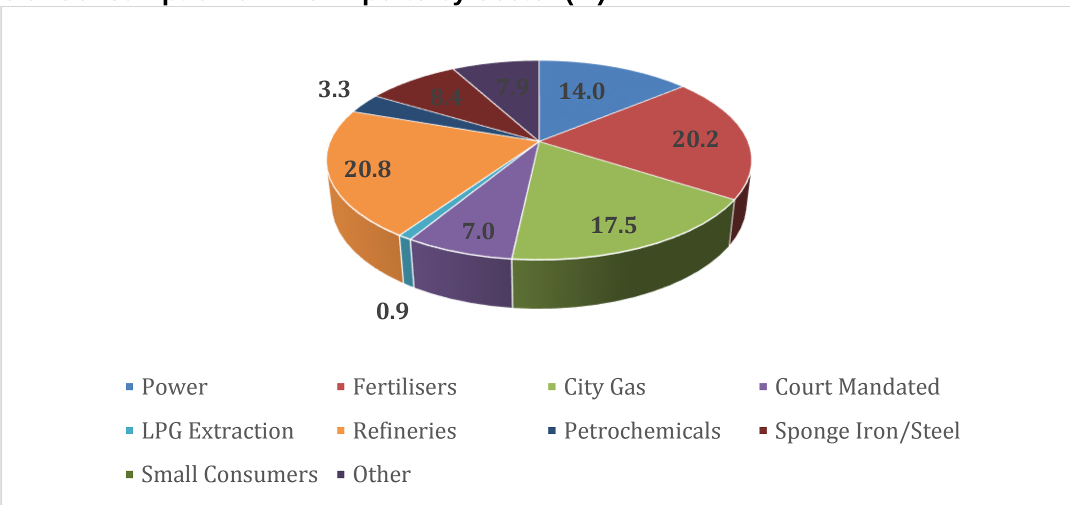
[63] A change to the priority order in July 2014 moved city gas for households and transport to the top, displacing fertilisers.
[64] This category generally refers to commercial consumers who may not have been able to obtain domestic gas supplies under the gas utilisation/allocation policy.

Figure 8: Consumption of Domestic Gas by Sector (%)



Source: BCG (2013); PNGRB (2013)

Figure 9: Consumption of LNG Imports by Sector (%)



Source: BCG (2013); PNGRB (2013)

Tier 1 consumer demand is met at controlled prices, specifically for the fertiliser and power sectors. City Gas entities supplying to households operate at the level of Indian states and are unregulated; therefore they are technically able to pass through price rises to their consumers, although, state governments have in the past stepped in to prevent price increases. Similar constraints apply to City Gas for transportation. Tier 2 demand is met through a combination of domestic gas and LNG imports, with a greater reliance on the latter. Indeed, while domestic gas is sold to Tier 2 consumers at prices set by the fiscal regime under which the gas is produced, the use of LNG implies that Tier 2 consumers can pay 'market' (import) prices. Although Tier 1 consumers account for just over 50% of LNG import consumption, as mentioned earlier prices are subsidised to these consumers, either directly or via pooling domestic gas and LNG imports to obtain a lower average price.

From the analysis of demand above, it is reasonable to conclude that the dynamics of demand amongst Tier 2 consumers (which primarily depend on LNG imports) are set to a large extent by the availability of domestic gas. This in turn is influenced by the demand amongst Tier 1 consumers – primarily fertiliser plants which have until very recently been at the top of the priority order, followed by power and to a lesser extent, city gas for households and transportation. Therefore, within the current

policy framework, the Tier 1 consumers – particularly fertilisers and power, set the dynamics of gas demand in India.

3.2.1 The Fertilisers Sector

India consumes roughly 30 million tonnes of fertilisers/year, second only to China (approximately 50 million tonnes).[65] Nitrogenous fertilisers – primarily urea, account for the majority of fertiliser consumption, followed by phosphates and potash. India manufactures about 22 million tonnes, with the remainder contracted through the international market, primarily on spot purchases, with a small proportion (roughly 2 million tonnes) through long-term contracts from Oman.[66]

Gas is used as an input to the manufacture of urea; alternatives to the use of domestic gas are LNG imports, naphtha, fuel oil/LSHS[67] and urea imports. Of these substitutes, domestic gas has exhibited the least price volatility, as prices are controlled at low levels. Figures 8 and 9 show that the Indian fertilisers sector accordingly accounts for 36% of domestic gas consumption and 20% of the consumption of LNG imports.

Jain (2011, pp.118-127) provides an analysis of fertiliser pricing policy in India, which shows that successive governments have promoted the use of domestic gas in fertiliser production in pursuit of the objective of 'self-sufficiency'. This policy has required all naphtha and fuel oil/LSHS urea manufacturing plants to be converted to gas-based plants with a view to the greater use of domestic gas in urea.[68] Table 4 shows the composition of urea manufacturing capacity by feedstock, as of 2012 – gas-based plants account for 81% of total capacity.

Table 4: Feedstock for Urea Manufacturing in India

Type of Feedstock	**No. of plants**	**Production Capacity (million metric tonnes)**	**Share (%)**
Gas	21	17	81
Naphtha	4	2	9
Fuel Oil/LSHS	4	2	10
Total	29	21	100

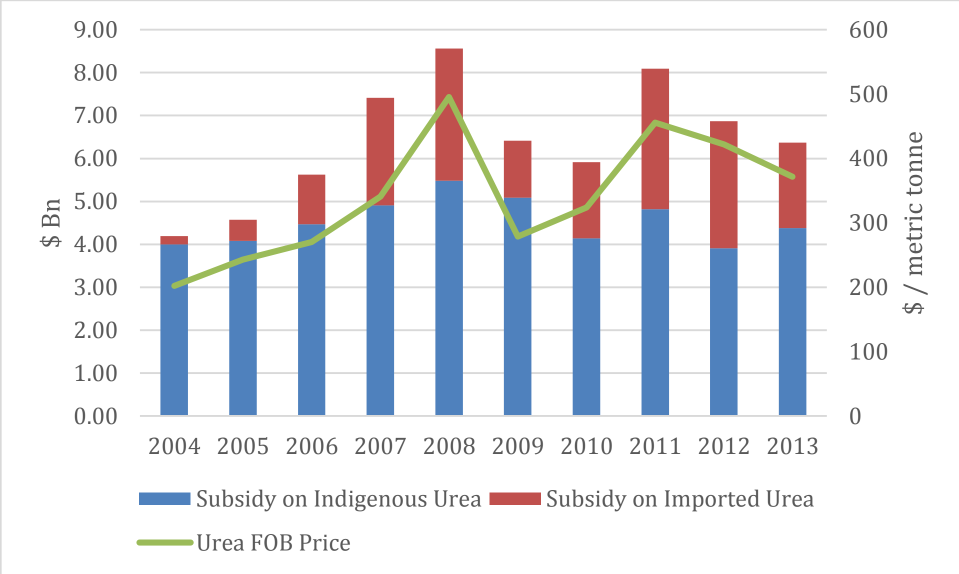
Source: GoI (2012b)[69]

Since 2008, the prices of domestically manufactured urea have been linked with the price of domestic gas.[70] A 'new investment policy' for urea in 2012 classifies urea manufacturing projects (plants) into 'revamp[71]', 'expansion', 'brownfield' and 'greenfield' projects and sets the price of urea to producers, produced under each of these, along with a floor and ceiling that are calculated to take into account a delivered gas price range of \$6.5/MMBtu to \$14/MMBtu.[72] However, the retail price of urea (to the

[65] Indian Fertiliser Scenario (2013)
[66] This is facilitated through a joint venture company – Oman India Fertiliser Company (Omnifco). The long term contracted price for urea from Omnifco is \$135/metric tonne as against \$300/metric tonne for spot purchases. For details see 'Supply of Urea by Omnifco' at http://fert.nic.in/node/1424
[67] Low Sulphur Heavy Stock – refers to a grade of crude oil.
[68] Jain (2011)
[69] GoI (2012b)
[70] Jain (2011, pp.125)
[71] This refers to the revival of mothballed plants.
[72] GoI (2014a); also see http://fert.nic.in/node/1380 . The floor and ceiling prices in \$/metric tonne for domestically manufactured urea are as follows: Revamp projects - \$ 245, \$ 255; Brownfield projects - \$285, \$310; Greenfield and Revival Projects - \$305, \$355.

farmer) is subsidised by about 50%[73] implying that the linking of its price to a wider range of domestic gas prices has had little or no direct impact on reducing the government's subsidy bill.

Figure 10: Fertiliser Subsidies in India, 2004-13 (in 2013 prices)



Source: Indian Fertiliser Scenario (2010; 2013); Economic Survey (2013); Planning Commission Databook (2014)[74]

The method of paying out subsidies has however, undergone reform since 2009. It moved from being paid to the manufacturer or importer, to being paid directly to the retailer. It is now beginning to be paid directly to farmers through a new social security programme (the Unique Identification Number system – 'Aadhar') which is being rolled out in phases across Indian states. The current government has indicated that it will continue with the programme, and will link subsidies directly to the bank accounts of eligible consumers.[75]

Figure 10 above shows the government's total subsidy bill (measured on the left vertical axis) for urea in 2013 prices – it is evident that the subsidy bill has been driven by changes in the price of imported urea (measured on the right vertical axis). Further, GoI (2012b) estimates that 85% of the increase in the total subsidy bill since 2005 can be attributed to fluctuations in urea import prices, and 15% to an increase in urea consumption.

The Indian Petroleum and Natural Gas Regulatory Board's 'realistic' projection (which adjusts the official Five Year Plans downwards) is for gas demand in fertilisers to rise from 22 Bcm at present to 40 Bcm by 2021. Fertiliser subsidies are likely to continue in the foreseeable future, as fertiliser consumers (farmers) represent over 50% of the electorate.

[73] (Jain, pp.119-121)
[74] Urea f.o.b. price for 2013 is an estimate based on an average decline of $50/tonne from previous year. See 'Urea imports down by 30% to Rs. 15,353 crore in 2013-14', *Moneycontrol.com*, 03 May 2014. http://www.moneycontrol.com/news/economy/urea-imports-down-by-30-to-rs-15353-cr2013-14_1078890.html
[75] 'Nandan Nilekani Lauds Prime Minister Narendra Modi for continuing Aadhar' *Economic Times*, 9 October 2014

3.2.2 The Power Sector

Gas-based installed generation capacity at 18 Gigawatts (GW)[76] accounts for just under 10% of total installed generation capacity (about 200 GW), most of which is coal (60%). The power sector accounts for about 35% of domestic gas consumption, and 14% of LNG imports. Electricity is a concurrent subject in the Indian Constitution, implying that states have relative autonomy in the implementation of electricity policy – which includes legislation, reforms, taxation and tariffs. Of total installed capacity, 37.4% is owned and operated by states, 27.3% by the federal (central) government, and 35.3% by the private sector.[77]

Jain (2011, pp.127-135) provides an analysis of the development of the market for gas in power. The power sector reflects the transitional nature of the gas sector and the wider economy, where a nascent but growing market (facilitated though electricity trading on power exchanges – currently roughly 11% of total power consumed) exists alongside state-regulated structures. This has led to the uneven development of the power sector across Indian states. Table 5 shows the regional distribution of installed power capacity by fuel.

Table 5: Regional Distribution of Power Generation Capacity in 2012 (Megawatts)

Region	Hydro	Coal	Gas	Diesel	Nuclear	Other	Total
North	15,123	28,358	4,421	13	1,620	4,391	53,926
West	7,447	38,924	8,255	18	1,840	7,910	64,394
South	11,338	22,882	4,691	939	1,320	11,569	52,740
East	3,882	21,798	190	17	-	399	26,286
Northeast	1,220	60	824	142	-	228	2,454
Islands	-	-	-	70	-	6	76
All	38,990	11,2022	18,381	1,200	4,780	24,503	199,877
% of All	19.4	56.4	9.1	0.5	2.4	12.1	100

Source: PNGRB (2013)[78]

The table reflects problems with the underdevelopment of infrastructure – for instance, gas-fired power generation in the eastern region of India is extremely low in comparison to the northern, western and southern regions, despite the fact that the largest offshore gas discoveries have been made in the eastern offshore basin.

The demand for gas in the power sector is influenced by two major factors. The first relates to the system of merit-order dispatch which prioritises cheaper fuels in electricity generation. This implies that the demand for gas-based power is influenced to a great extent by the price and availability of domestic or imported coal. It is estimated that for existing plant, a base-load Open Cycle Turbine can compete with coal at gas prices of \$5-\$6/MMBtu, a Combined Cycle Gas Turbine at \$8-\$10, and peaking power plants and Combined Cooling Heating and Power plants at a price slightly above this.[79] The second factor influencing the demand for gas in power, particularly for privately owned capacity and off grid captive generation plants, is state-level regulations on power relating to open access to infrastructure, and third party use. The lack of clear regulations in this area[80] has meant that even where there is demand for power at a higher price (for instance from industry), state regulations could prevent the gas (including LNG) from getting to potential consumers.

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[76] This excludes off grid captive generation plants.

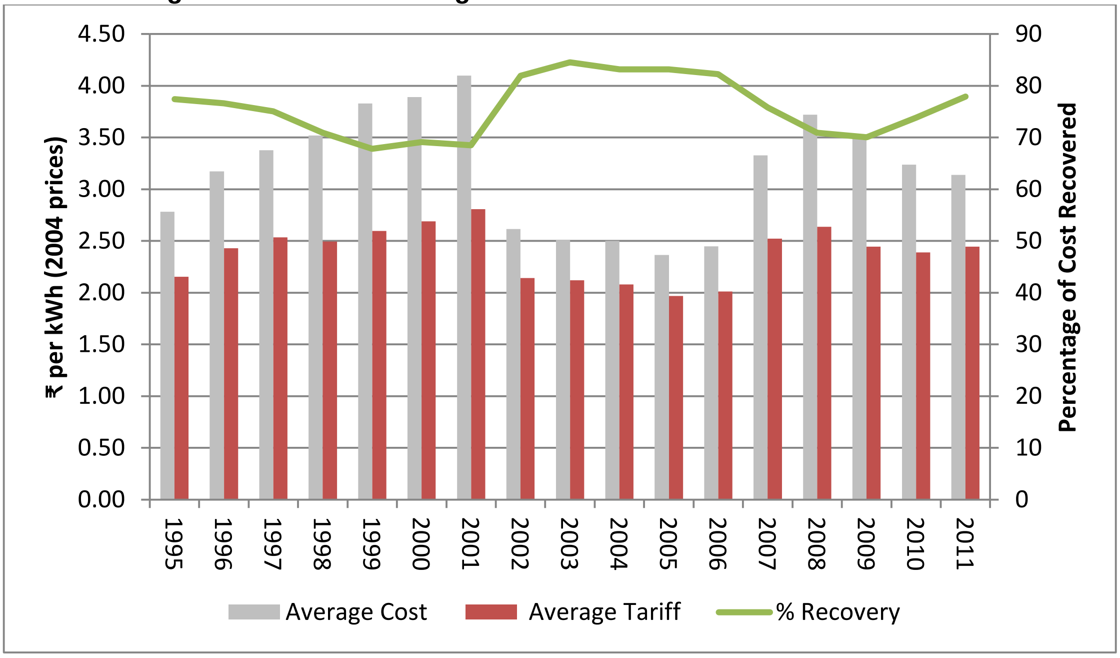
[77] Ministry of Power, Government of India

[78] PNGRB (2013)

[79] GoI (2011)

[80] States have in the past resisted granting third party access as this may lead to a flight of consumers from loss-making public sector utilities.

Figure 11: Average Costs versus Average Tariffs in Power



Source: Sen and Jamasb (2013)

The combined effect of the two factors above is evident in the current situation in the power sector. A decline in domestic gas production has led to a decline in the Plant Load Factors of gas-based plants to around 50%, resulting in a significant amount of idle capacity. This is ironic given that peak electricity deficits consistently run at 9-12%, and reflects systemic failures.

Added to this is the fact that most state-owned utilities subsidise power to certain consumer segments (primarily agricultural consumers), and therefore do not recover their costs. Figure 11 above shows the average tariff for power versus the average cost of production on the left vertical axis, as well as the percentage of cost recovered from tariffs on the right vertical axis.

Despite financial problems in the power sector, the Indian Petroleum and Natural Gas Regulatory Board envisages an addition of 20GW of gas-fired capacity in each five year period between 2017 and 2032 at a Plant Load Factor of 75%. It adjusts the Five Year Plan forecasts (which are overly optimistic) downwards, suggesting that gas demand in the power sector will increase from 32 Bcm at present to 85 Bcm by 2021. In addition to the fact that plan targets have very rarely been met, the materialisation of this additional capacity will depend on the resolution of regulatory problems in the power sector. Realistically, investment in gas-fired power will not be forthcoming unless higher-priced gas is able to find a market in the power sector – that is, either be able to compete with coal, or find its way to price inelastic consumers.

3.2.3 City Gas for Households and Transportation

City gas demand is split between Tier 1 (households and transport) and Tier 2 (commercial and industrial) demand – therefore Tier 1 consumers utilise primarily domestic gas but also some LNG imports, whereas Tier 2 consumers utilise domestic gas left over from Tier 1 demand plus LNG imports.

City gas is a relatively new and expanding gas consuming sector. Jain (2011, pp.135-138) describes how city gas is primarily an urban commodity, which established its market share through the enforcement of environmental legislation to combat pollution in cities. Consequently, there are 1.2 million vehicles that run on Compressed Natural Gas (CNG) – representing just under 1% of the total

fleet of registered motor vehicles, and 943 CNG service stations.[81] CNG has acted as a catalyst for the growth of natural gas in other uses.

Piped Natural Gas (PNG) is used by households (domestic consumers), commercial consumers and industrial consumers.[82] There are 2.6 million household PNG connections, and 27,073 commercial and industrial consumers spread out over 43 geographical areas covering major metropolitan cities in thirteen states.[83] There are plans to add 60 further geographical areas by 2021 by awarding bids for the development of network infrastructure. The sales volumes of the three main city gas distribution companies – Indraprastha Gas Limited (IGL), Mahanagar Gas Limited (MGL) and Gujarat Gas Company Limited (GGCL) – have grown at roughly 9%/year from 2007-2011.[84]

Although city gas for households and transportation is prioritised as a Tier 1 consumer under the government Gas Utilisation Policy, city gas distribution companies do not have restrictions on passing on changes or increases in prices to consumers (households and transport). Accordingly, it has been estimated that the city gas segment can support gas prices of $12-$16/MMBtu.[85] However, on occasion, state governments have stepped in to prevent increases in the retail prices of PNG and CNG.

City gas demand is influenced by the prices of its fuel substitutes. In CNG this is petrol or diesel, and in PNG, this is primarily Liquefied Petroleum Gas (LPG). Petrol is priced at international rates at the retail level, and the subsidy on diesel has been progressively eliminated over the last 18 months.[86] LPG however continues to be subsidised in its retail price for household consumers, but the quantity of LPG sold at the subsidised price to each household is capped.[87]

At present, city gas accounts for 8% of domestic gas consumption, and 18% of LNG import consumption. The ‘realistic’ forecast of demand for city gas carried out by the Indian Petroleum and Natural Gas Regulatory Board envisages demand growing from 6 Bcm/year at present to about 17 Bcm/year by 2021. The recent re-categorisation of city gas for households and transportation to the top of the priority order in the Gas Utilisation Policy suggests that there may be future potential for demand to grow beyond these numbers. The fact that city gas distribution entities are allocated domestic gas at low prices but can adjust their retail prices in fact presents an opportunity for investment in the city gas distribution sector.

3.2.4 Tier 2 Demand

Gas consuming sectors in the ‘Tier 2’ group (in table 3) rely primarily on LNG imports, as seen in Figures 8 and 9. Of these, refineries make up the majority of consumption (21%) followed by sponge iron and steel (9%). The Indian refining sector has grown at 5.4%/year since 2003, and refining capacity stood at 4.35 million b/d in 2013, making India the largest refiner in Asia after China. It is further estimated to grow at 9.6% over the next 4 years.[88] Refineries have been able to support higher gas prices, as the alternative inputs to gas have included higher cost crude and naphtha. However, the Indian export refining sector, which has been largely responsible for India’s refining boom, will face growing competition from new refining capacity in its traditional demand bases in the Middle East, as well as competition in neighbouring East Asian markets due to a slowdown in demand in

[81] GoI (2011); GoI (2014c)
[82] GoI (2011); GoI (2014c)
[83] GoI (2011); GoI (2014c) These states include the National Capital Territory of Delhi, Maharashtra, Gujarat, Rajasthan, Uttar Pradesh, Andhra Pradesh, Assam, Haryana, Telangana, Madhya Pradesh, Punjab and Tripura.
[84] GoI (2011); GoI (2014c)
[85] GoI (2011); GoI (2014c)
[86] Oil marketing companies were reported to have made a profit on sales of diesel in September 2014, for the first time in decades.
[87] This is capped at twelve 14 kg cylinders/household.
[88] EIA (2013)

China (along with excess refining capacity, which could lead to greater Chinese exports of petroleum products).[89]

3.2.5 Summary

From the analysis of demand above, it is reasonable to make the following observations:

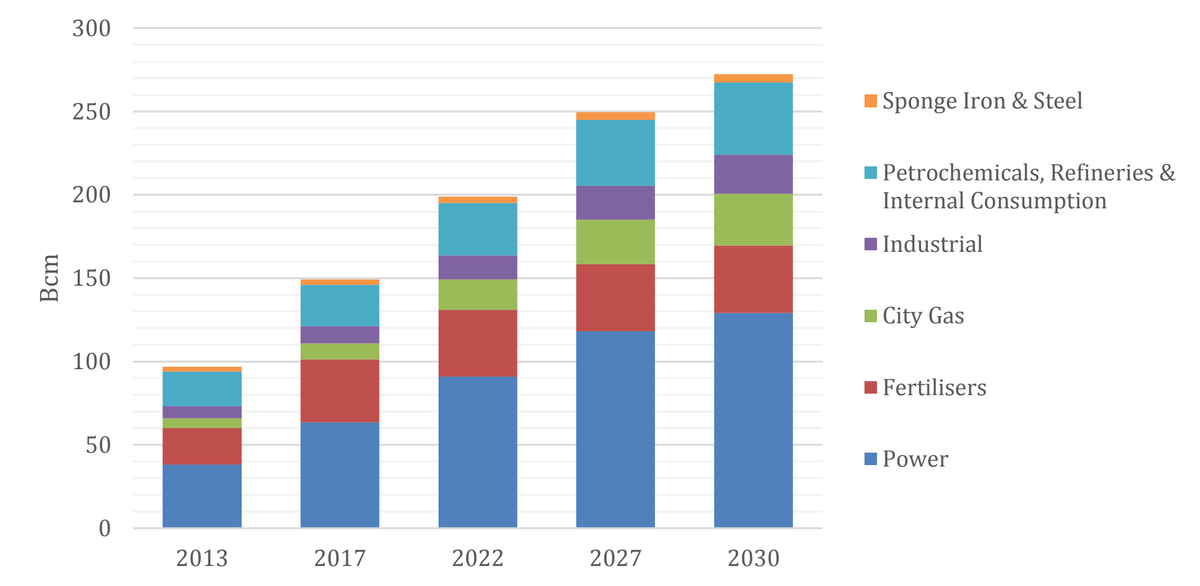
- The current structure of demand (or use) of gas is set by the fertiliser sector and the fertiliser subsidy. The fertiliser sector represents 'captive' demand, following the mandatory switchover of urea manufacturing plants from naphtha to gas as the main input. It is likely that there is latent gas demand in the fertiliser sector – evident in the use of high cost urea imports to meet the deficit between the production and consumption of urea, rather than allowing changes in the domestic gas price. There is, therefore, a case for raising gas prices to the point that they could stimulate domestic gas production, which could potentially mitigate the subsidy bill – both in terms of total expenditure on subsidies, as well as the volatility brought about by changes in the international prices of urea (in the longer term). It is plausible that fertiliser demand could rise to meet new supplies.
- The power sector also represents a 'captive' segment of gas demand as gas-based power plants essentially represent a sunk cost. However, the demand for gas in power is set by the price and availability of domestic and imported coal, and the potential for gas in power is constrained by regulation – particularly relating to third party access to electricity infrastructure – and the deteriorating finances of state-owned utilities.[90]
- The city gas sector holds the best potential for expansion in the use of gas at higher prices, given the lack of price controls on city gas distribution companies. Demand from this sector could rise if new supplies were available.

Figure 12 provides a consolidated forecast of gas use to 2030, based on the Indian Petroleum and Natural Gas Regulatory Board's downward adjustments of India's official Five Year Plan forecasts.

[89] Bose (2015)

[90] This is because, as discussed, state-owned utilities are reluctant to lose industrial consumers (who cross-subsidise agricultural consumers) who are most likely to opt for higher priced gas-based power.

Figure 12: Forecast of the Use of Gas by Sector

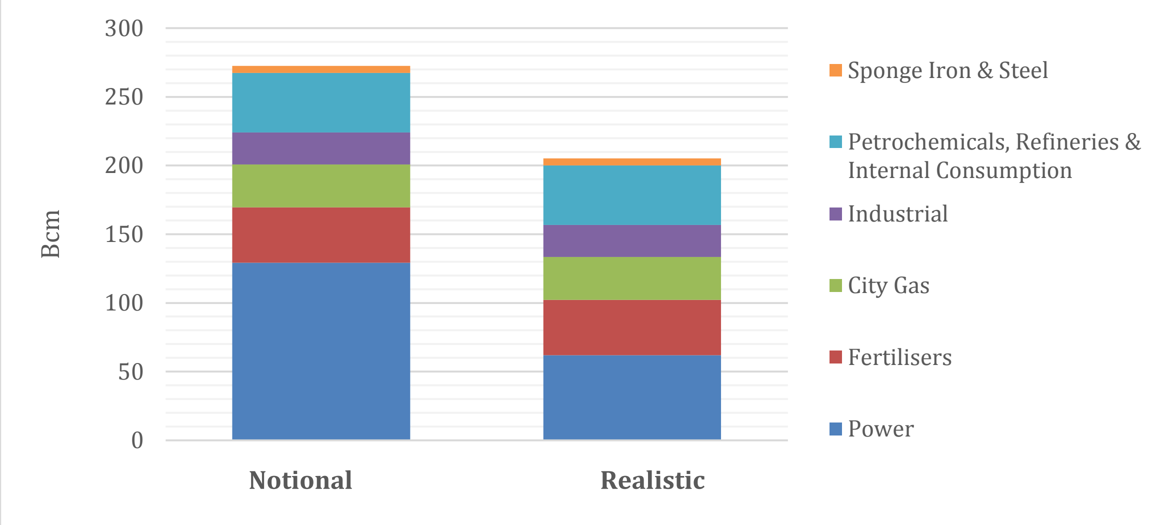


Source: PNGRB (2013)

According to this consolidated forecast the majority of gas demand will come from the power sector – however, as this discussion has pointed out, this is also the sector that is most in question when it comes to ascertaining the demand for gas in India. The IEA (2013) World Energy Outlook supports this conclusion, as the estimates of demand for gas in power generation are nearly half the total forecast in figure 12. Whilst investments in expansion and new capacity in the entirely publicly-owned fertiliser industry are plausible, as are investments in the expanding city gas sector, opportunities in the power sector are contingent on the price of coal. There are potential pockets of demand in ‘captive generation’ (a ‘Tier 2’ consumer group) –estimated to be equivalent to a third of total installed capacity, but this will depend on their ability to access higher priced gas through very complex and uneven state regulations.

Adjusting the Indian Petroleum and Natural Gas Regulatory Board’s notional forecast for 2030 to take into account the lower projections for the power sector, we obtain figure 13 below which puts total potential gas ‘demand’ in India at approximately 200 Bcm in 2030. This roughly corresponds with the IEA (2014) World Energy Outlook forecast for the overall demand for gas in India.

Figure 13: Notional versus Realistic Demand, 2030



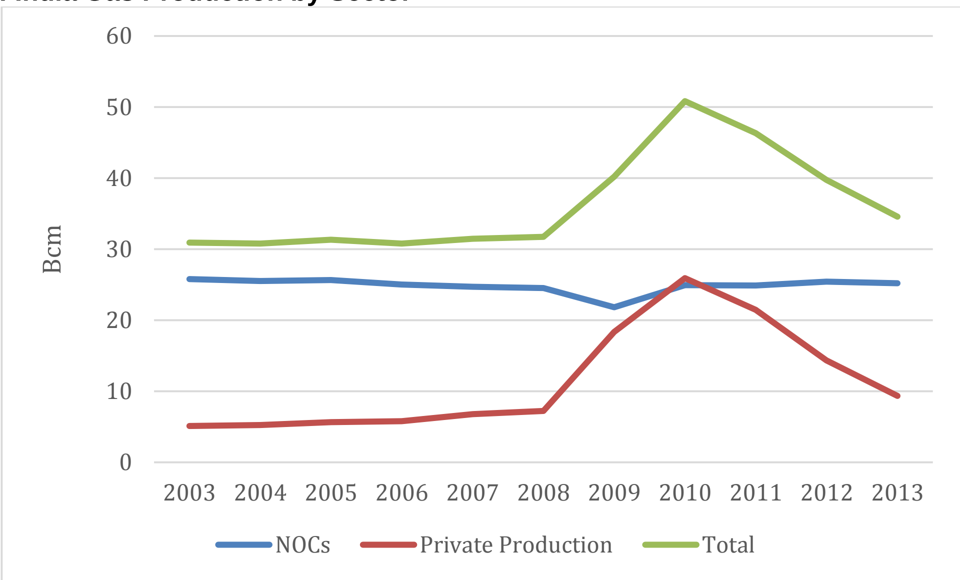
Source: Author's analysis; PNGRB (2013); IEA (2014)

The discussion above suggests that the demand for gas in the power sector – estimated as the largest contributor to future demand – may have been overestimated. *The analysis above indicates that there may be latent demand for gas in fertilisers, which is currently being constrained by inadequate domestic supply.* However, the question remains as to whether customers in this category would be willing and able to pay a price which could incentivise new gas exploration and production. We explore this further in Section 5.

4. Impact on Domestic Supply

The Indian upstream gas sector has experienced a serious downturn over the last 4 years. Following the 2004 'KG-D6' gas discovery in the eastern offshore basin (operated by Reliance Industries Limited (Reliance) and BP), private sector production briefly overtook public sector production (from ONGC and OIL – the two NOCs). However, since 2010, private sector production has been steadily falling, while production by the NOCs remains steady. Figure 14 shows this decline. The KG-D6 estimated reserves have since been revised downwards from 10 Tcf to around 3 Tcf.

Figure 14: India Gas Production by Sector



Source: PPAC (2014)

The reasons for this decline, driven by falling production in the KG-D6 block, have been much speculated upon but they are indeterminate because they are based only on data available in the public domain. Two possible reasons can however be sketched out for this decline: first, for technical reasons the field may not have performed as expected because of unexpected reservoir conditions. And second, the cost of development may have turned out to be higher than anticipated (for whatever reason), with the result that the operator or consortium could have been losing money at the obtainable gas price and as a consequence may have curtailed production. It is however beyond the scope of this paper to make any sort of judgment on this issue.

However, the Reliance gas pricing dispute (as it has come to be known) has been extensively written about.[91] The 2013 gas pricing reform was due to come into effect on 1 April 2014, as was the review of the pricing clause in the Production Sharing Contract for KG-D6. Had the reform been implemented, KG-D6 gas would have been eligible for the higher price. This has led to speculation over the timing of the price reform and subsequently, arbitration and court proceedings between Reliance/BP and the Indian government. The question of gas price reform is important regardless of the outcome of these proceedings, as other gas producers including the NOCs stand to gain or lose from it.

[91] Jain (2011) provides a good factual summary.

Annual investments in India's upstream exploration sector have also been in decline, from a peak of $6 Billion in 2007, to $1.8 Billion in 2011, with few or none of the international majors participating in auction rounds.[92] Table 6 shows company holdings of exploration acreage as of 1 March 2014.

Table 6: Company Holdings[93] of Petroleum Exploration License (PEL) Acreages (%)

	% Acreage		% Acreage
ONGC	53.58	**Adani Welspun**	0.31
BHP Billiton	6.56	**GAIL**	0.25
Reliance (RIL)	5.27	**Deep Energy**	0.21
HOEC	4.72	**ESGPL**	0.09
Cairn India Limited	4.32	**ACL**	0.08
Santos	4.12	**Indian Oil (IOCL)**	0.07
OIL	3.44	**HCIL**	0.06
ENI	3.10	**Quest**	0.06
Prize Petroleum	2.65	**Omkar Natural**	0.05
Focue	2.56	**Mercator Petroleum**	0.05
BGEPIL	2.42	**BRPL / GAIL**	0.05
Deep Energy/DNRL	2.15	**NTPC**	0.04
JOGPL	1.39	**JPIL**	0.04
ESSAR	0.81	**Sankalp Oil**	0.03
Geoglobal Res	0.69	**Pratibha Oil**	0.02
HOEC	0.46	**Pan India/ Frost Int. Ltd.**	0.01
Bengal Energy	0.36		

Total Acreage: 38, 1601 Km^2

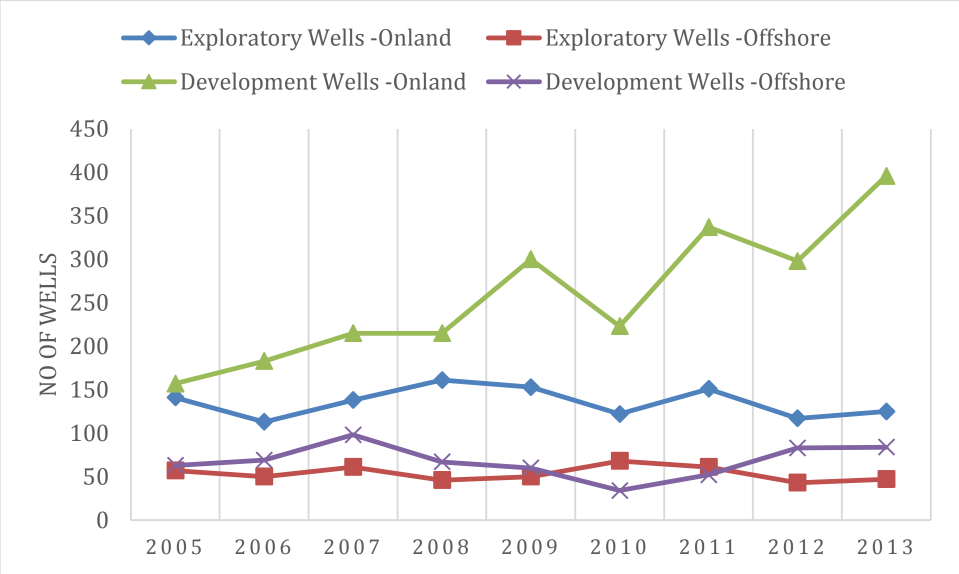
Source: DGH (2013)

The upstream government regulator – the Directorate General of Hydrocarbons – has also come under scrutiny for its alleged failure to enforce the terms of Production Sharing Contracts.[94] In an attempt to simplify the management and administration of exploration and production contracts, a new reform to the fiscal regime has been proposed which would replace PSCs with Revenue Sharing Contracts, where companies will be required only to pay royalties and share a percentage of revenues (as opposed to profits) from production at pre-agreed production levels (determined through auctions). Whilst some argue that this will simplify the monitoring of exploration activities (particularly cost) and prevent future disputes over the recovery of capital expenditure, others argue that it is a retrograde measure which will fail to incentivise companies to invest in riskier deep water offshore exploration.[95]

Figure 15 shows drilling activity over the last eight years. There has been a decline in the number of exploratory wells drilled for both offshore and onshore areas, although it is more pronounced for offshore areas. More generally, drilling activity in offshore areas has remained low relative to onshore areas, despite the fact that around 70% of PELs are held for offshore areas.[96]

[92] GoI (2013a)
[93] This refers to Operators. Therefore BP, for instance, which holds a stake in Reliance's eastern offshore blocks, is not listed.
[94] CAG (2011)
[95] Johnston and Johnston (2015)
[96] DGH (2013)

Figure 15: Number of Wells Drilled, 2005-13



Source: DGH (2005-13)

In this context, two important questions emerge with respect to the impact of gas pricing reforms. First, will gas pricing reforms reverse the decline in production? And second, will it lead to new investments in exploration and production?

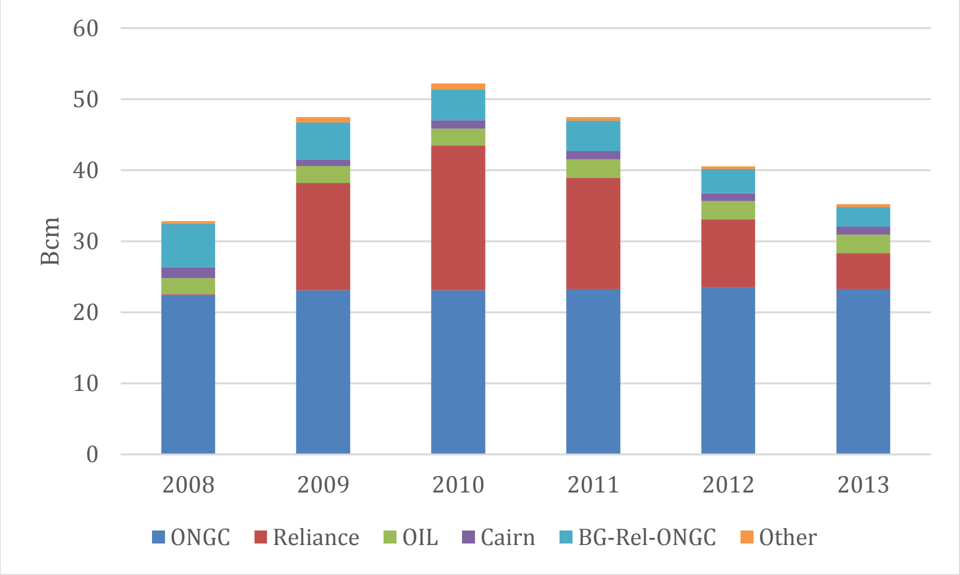
4.1 Will Gas Price Reforms Revive Domestic Production?

India's proven reserves of gas have been estimated at 1.4 Tcm by official government data and the BP Statistical Review of World Energy 2014. India is not a 'gas-rich' country, as reserves represent just 0.7% of total world gas reserves. The upstream exploration sector which was traditionally dominated by the NOCs was opened up to private investment 15 years ago in a bid to attract capital and technology. To date, of India's total exploration acreage, roughly half is 'poorly explored' or unexplored.[97]

The discovery of eastern offshore KG-D6 gas in 2004 sparked a brief renaissance in the Indian gas sector. Production from this discovery began in 2009 and was followed quickly by a revision (doubling) of the domestic gas price from $1.79/MMBtu to $4.20/MMBtu. This revival was short lived, and production began declining from 2011 due to the possible reasons stated earlier.

[97] DGH (2012)

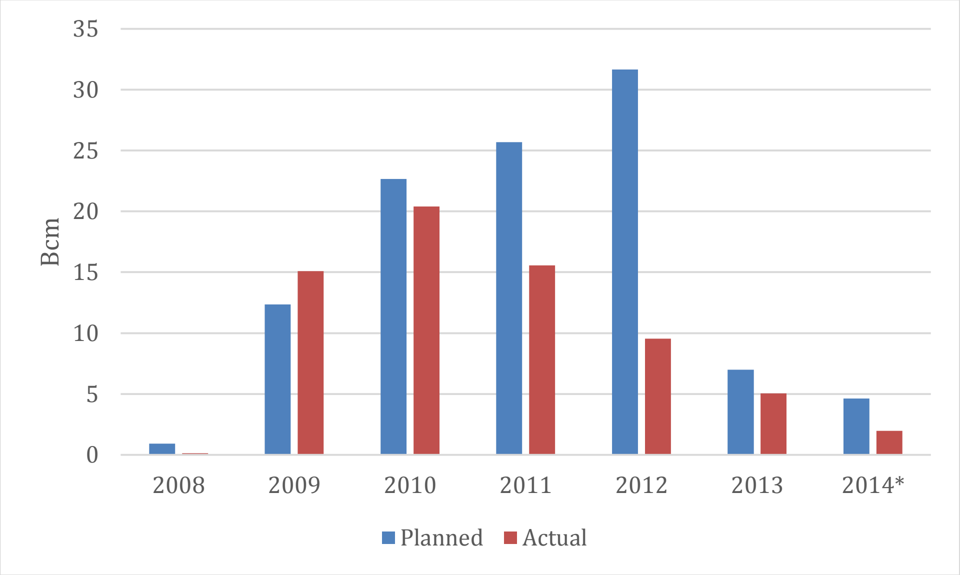
Figure 16: Gas Production by Company (2008-2013)



Source: DGH (2008-2013); Author's estimates

Figure 16 shows private sector production declining from 2011 driven by falling output from Reliance's gas fields. Figure 17 shows the planned targets for the KG-D6 block, compared with what was actually achieved, further illustrating the extent of the decline.

Figure 17: Planned versus Actual Production, 'KG-D6' Block

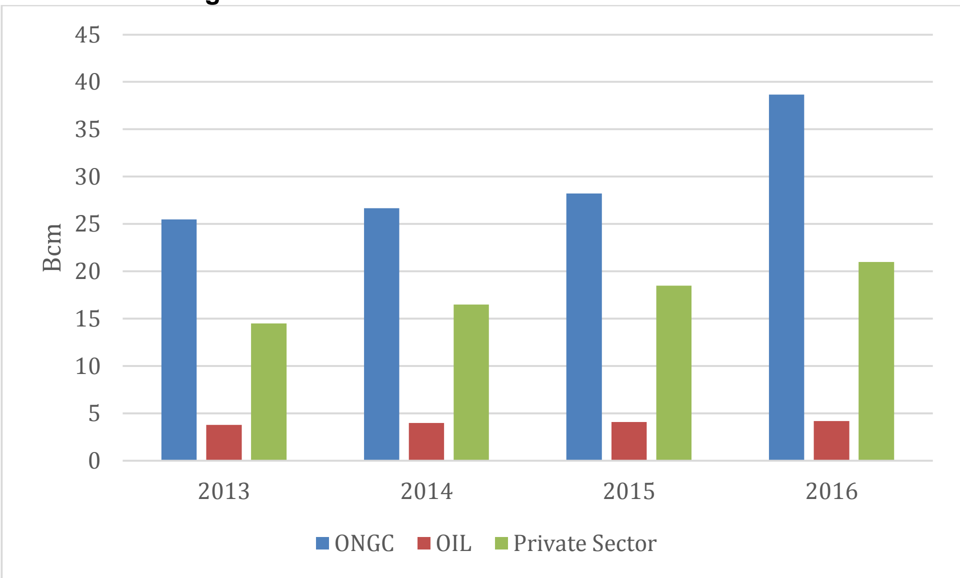


Source: GoI (2013a; 2014c); *Apr-Aug data for 2014

Consequently, production from the block was roughly 9 Bcm in 2012, which was 22 Bcm short of the originally planned target. This shortfall is equivalent to the entire annual volume of LNG which was typically imported by India in the immediate preceding years. – in other words, it represents a potential doubling of India's LNG import requirements. The 2013 production target was revised downwards, but was still failed to be met. Production appeared to have picked up marginally in 2014 (when extrapolating for full year 2014).

Figure 18 shows the short to medium term production targets estimated by the Indian government in its 12th Five Year plan.

Figure 18: Production Targets for India's 12th Five Year Plan

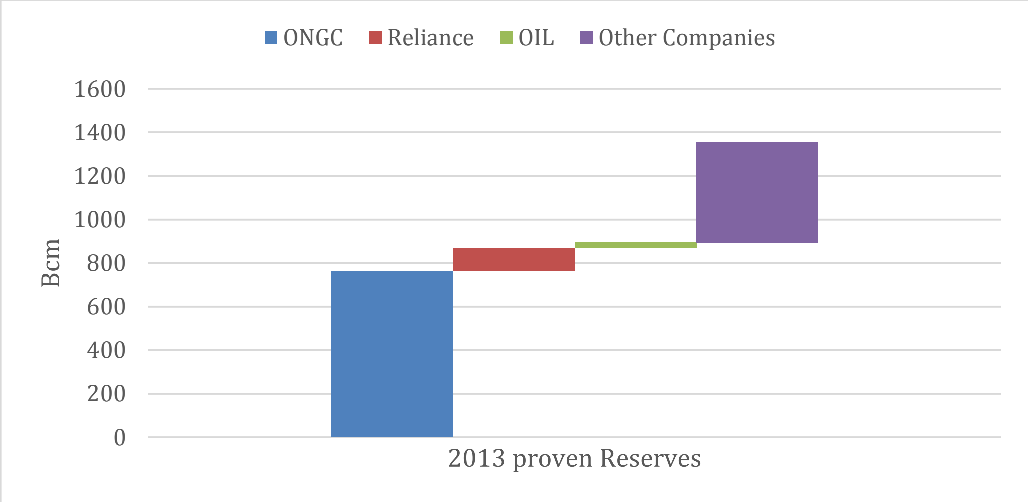


Source: GoI (2012a)

These targets have been revised downwards to take into account the decline in private sector production, but even so, they envisage private sector production going back up to just over 20 Bcm by 2016 – this is fairly optimistic as it represents the entire amount of lost production being made up within the next two years. Further, Figure 18 shows that ONGC's production targets for 2016 are roughly 39 Bcm, up from 24 Bcm at present. Therefore, five-year plan targets include adding a total of 44 Bcm of domestic gas supplies (from ONGC plus private sector alone) by 2016. In January 2015 ONGC announced that it was targeting production of 40 Bcm by 2019/20, an 80% increase from current levels but this would either require another significant discovery larger than or on the scale of the original KG-D6 block estimates – which envisaged production ramping up very quickly (to just over double) within a space of three years, or for an adequate number of 'marginal' fields to be brought into production. Both are contingent on price.

Figure 19 shows India's 1.4 tcm of proven reserves broken down by company holdings. ONGC has the largest reserve holdings, as they include its legacy fields from the Nomination Regime. Apart from Reliance and OIL, other companies with holdings of gas reserves include Cairn India – a relatively small but successful player in the upstream sector, and BG India.

Figure 19: Proven Reserves by Company



Source: Company Data[98]; Author's estimates

As of 1 March 2013, most Petroleum Exploration Licenses (PEL) (roughly 80%) were held for offshore areas and, the majority of PEL acreage was split between ONGC and Reliance – which held roughly 49.4% and 26.6% respectively. By 1 March 2014, the percentage of Petroleum Exploration Licenses held for offshore areas was reported at 70%, and the percentage of PEL acreage held by ONGC and RIL was reported at 53.6% and 5.3% respectively.[99] This may have been due to the relinquishment of acreage. In contrast, Mining Licenses[100] are split halfway between onshore and offshore areas. This indicates that the potential for new gas production lies primarily in offshore areas.[101]

Given its reserve holdings, it is evident that ONGC is best placed to add to India's gas production. Yet, production from ONGC's field plateaued in the early 1990s, and has remained stagnant since. One reason for this could be ONGC's cost of production relative to the tightly controlled domestic gas price. As one of India's most valuable NOCs, the company has been utilised in the past to subsidise oil and gas sales to retail consumers, and to share the government's total subsidy burden in a strategy aimed at mitigating the fiscal deficit.[102]

Figure 20 shows ONGC's average cost of production for offshore gas relative to the domestic gas price. It is clear that ONGC was making losses from the production of gas until 2010, when the price was doubled from $1.79/MMBtu to $4.20/MMBtu. At a price of $4.20, it just broke even, and according to company data before paying out taxes and dividend it was left with a margin of roughly $0.58/MMbtu.[103] OIL, the other important NOC, is in a similar position although it is a much smaller player in gas than ONGC.[104] In contrast with the NOCs, the 19th Parliamentary Standing Committee on Petroleum and Natural Gas reported in 2013 that Reliance's cost of production in 2011 was $2.48/MMBtu without taxes/levies and $2.74/MMBtu with taxes/levies. [105]

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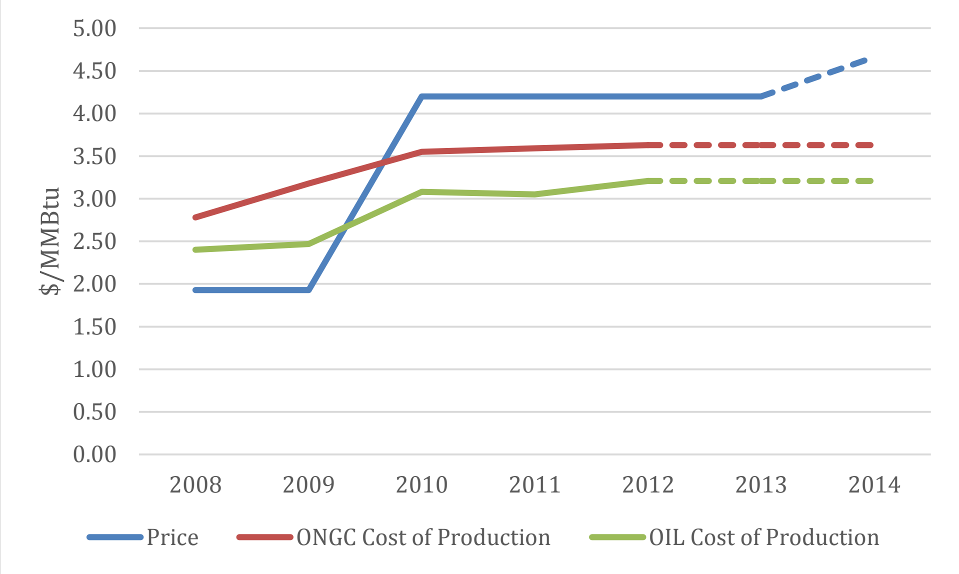
[98] Investor Presentations and Annual Reports
[99] DGH (2013; 2012)
[100] Representing permits for gas production.
[101] This excludes shale gas potential, which is entirely separate.
[102] This could potentially render ONGC's financial situation precarious. However, ONGC has several business streams, some of which are profitable. Its profit-making ventures essentially cross-subsidise government policy on controlled pricing.
[103] ONGC Investor presentation (2013). The effective margin after taxes and dividend was reported at $0.21/MMBtu.
[104] Data on OIL is for cost of production from onshore gas blocks as OIL does not have any production from offshore areas.
[105] GoI (2013a). The Standing Committee reported this as an estimate based on projected levels of production, and this was unverifiable by the author.

Figure 20: Average Cost of Production of Indian NOCs versus Domestic Price



Source: Source: GoI (2013a)

ONGC's future plans involve reversing the decline in output from its older western offshore reserves, whilst simultaneously developing its new eastern offshore reserves. In 2014, ONGC reported that it had made 14 discoveries, of which 12 were of gas or oil and gas.[106] The company plans to increase its output by 2020 by focusing on three developments. The first is its western offshore shallow water marginal fields at Daman which have estimated reserves of around 36 Bcm, and are capable of producing 4-5 Bcm/year by 2020 and from which it expects gas to begin flowing from August 2016.[107] It has been reported that these fields would be economically viable at a price of $5-$5.4/MMBtu.[108]The second focus is on a significant new gas discovery in its eastern offshore reserves in the KG-DWN 98/2 block, estimated to hold 137 Bcm of proven reserves, capable of producing 13 Bcm/year and scheduled to come into production in 2017. However, ONGC recently reported that it would require a price of $6-$7.15/MMBtu to produce from this discovery, as the cost of production for the block is estimated at $4.43/MMBtu.[109]

The third major focus of production for ONGC is its Mahanadi basin deep water blocks, which it has reported capable of producing 20 Bcm with reserves of 1 Tcf. However, in September 2014, the company reported that it was deferring its plan to develop these blocks as the economically viable price was estimated at $10.72-$12.63/MMBtu, in contrast with the $4.20/MMBtu domestic gas price at the times. *Without the Mahanadi production and assuming a higher domestic gas price of at least $6-$7/MMBtu, the potential increase in output from ONGC's reserve is 18 Bcm* – this is unlikely to come online before 2017, and some reports state that ONGC is 4 years away from any new production due to various procedural and policy delays.[110]

Reliance had, up to 1 March 2013 according to official statistics, held the second highest proportion of acreage (30%) after ONGC (49%), and therefore had significant potential to boost its production.

[106] ONGC Investor Presentation (2014).
[107] See 'ONGC Plans Big with Small Daman Fields, Financial Express, 17 September 2014. http://www.financialexpress.com/news/ongc-plans-big-with-small-daman-fields/1289834/0
[108] Ibid
[109] See 'ONGC says needs $6-7.15 to break even', The Economic Times, 2 September 2014, http://articles.economictimes.indiatimes.com/2014-09-02/news/53480016_1_kg-dwn-98-2-gas-production-kg-d6
[110] See 'Oil Ministry sets up panel on delays in ONGC's gas discovery', The Economic Times, 3 October 2014, http://articles.economictimes.indiatimes.com/2014-10-03/news/54599788_1_kg-d5-cairn-energy-india-ltd-kg-d6-block

(This had dropped dramatically in the official statistics reported for 1 March 2014 as shown in Table 6). Reliance and its main equity partner BP have indicated that they will not invest further in developing gas production unless the price issue is resolved. At higher gas prices, Reliance has stated that it can potentially increase its output 'fourfold' by 2020.[111] At current levels of production, this would take its output back up to 20 Bcm. This increase would be likely to come from several sources. The first would be the development of its R-Cluster fields, estimated to hold 1.2-1.4 Tcf with an estimated peak production of about 4.4 Bcm/year – the Field Development Plan for this was approved in August 2013 and first production could come online in 2017.

The second source would be the development of satellite discoveries including D2, D6, D19 and D22, yielding roughly 4 Bcm/year. The third would include a major gas discovery in its eastern offshore block in 2013 – D-55 – which has yet to be appraised, but which could add another 3-4 Bcm/year. Reliance has estimated that this could take two years to bring into production and would involve an investment of $10 Billion. A fourth potential source is its D-56 discovery in the Cauvery basin, which again has yet to be appraised. Reliance/BP had also planned a work-over of wells in the D1 and D3 fields on the expectation of a higher gas price, which would have reversed some of the decline in output from the KG-D6 block by 2015. *Pending the resolution of the price issue, this potential output of 20 Bcm/year is unlikely to come online as scheduled.*

To summarise, in the medium term (2020), it is likely that a major proportion of the decline in domestic production can be reversed (18 Bcm/year out of 22 Bcm/year) but only at a price of $6-$7.15/MMBtu which makes it economically viable for ONGC to develop its Daman and KG-DWN 98/2 discoveries. However, without additional production (potentially, Reliance-BP's 20 Bcm/year by 2020 – which is contingent on price reform) the government's official target of adding 44 Bcm/year by 2016 through boosting domestic production is unlikely to be realised. The target, in any event, is unlikely to be met by 2016.

Gas price reform at its current price level ($4.66) is unlikely to revive domestic production and reverse the decline brought about by the drop in KG-D6 production – it could revive production at prices in excess of $6-$7/MMBtu, but not significantly before 2020, given the general lead time involved in offshore field development.

4.2 Will Gas Price Reforms Lead to New Investments in India's Upstream Sector?

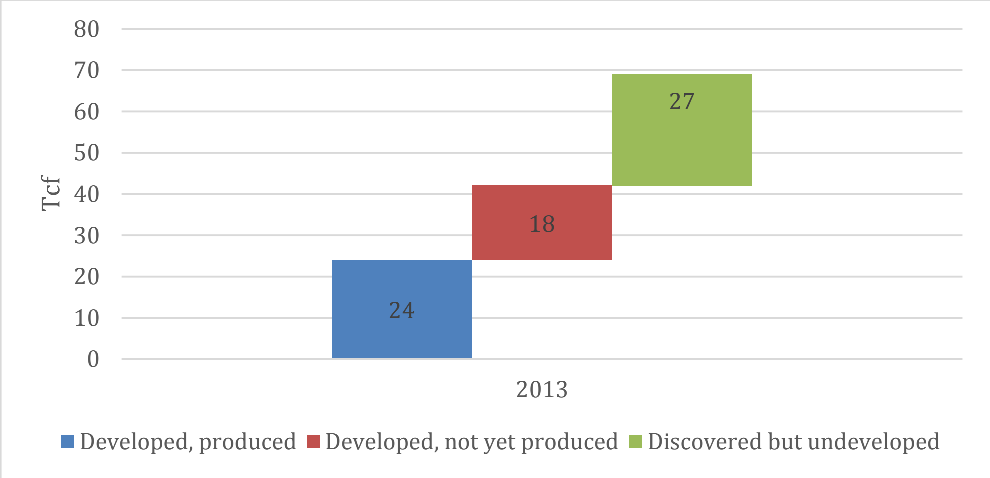
Whether gas price reforms will attract new investments in India's upstream exploration sector, leading potentially to greater domestic production in the long term (2022 and beyond)[112] depends on two factors:

- India's gas resource potential
- The attractiveness of investment opportunities in gas exploration, of which price is a key part

For the first factor we rely on publicly available estimates of India's gas resource potential. Proven reserves, as discussed previously, have been pegged at 1.4 Tcm. IHS[113] estimates that 69 Tcf of proved plus probable recoverable reserves have been discovered thus far in India. Figure 21 breaks this down into gas already produced, gas which has been developed but not yet produced, and gas that has technically been discovered but not developed.

[111] 'Prices Key to Progress at D6' *Upstream* - Petrotech 2014, 12-15 January
[112] Assuming an exploration cycle of 7 years, and that the next bidding round for exploration acreage is held in 2015, we can reasonably expect the earliest production from new investments by this date.
[113] Petrofed (2014); IHS Press Release (2014)

Figure 21: Gas Resource Potential



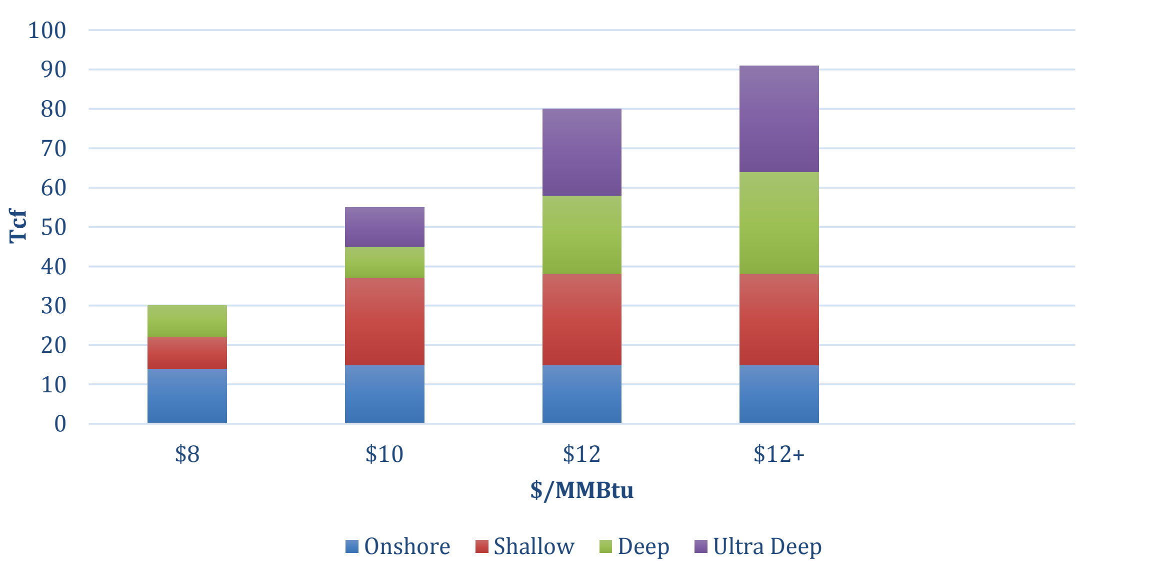
Source: Petrofed (2014); IHS Press Release (2014); Compiled by Author from publicly available reports[114]

Additionally, IHS estimates that there is potential for a further 64 Tcf of risked recoverable resources yet to be found through further exploration.[115] Adding this to the 27 Tcf of undeveloped discoveries from figure 21, there is potentially 91 Tcf of gas available for future development. Of this, a major proportion (53 Tcf) is split almost equally between offshore deep water and ultra-deep water, with 23 Tcf in shallow water and 15 Tcf onshore.[116] Roughly 50% of India's exploration acreage has yet to be appraised. Of onshore acreage, 65% has yet to be appraised, of shallow water offshore acreage – 22%, and of deep water offshore acreage, 49%.[117] It is reasonable to conclude that India's gas resource potential has not been fully exploited.

For the second factor we look at the prices at which it is possible to produce commercially[118] from these reserves. Figure 22 shows this.[119]

[114] 'India's gas production to stagnate without pricing reforms' *Economic Times*, 11 June 2014, http://articles.economictimes.indiatimes.com/2014-06-11/news/50508397_1_gas-production-gas-demand-pricing-formula ; 'India's bold move on gas prices', *Petroleum Economist*, 3 July 2013, http://www.petroleum-economist.com/Article/3226455/Indias-bold-move-on-gas-prices.html
[115] Petrofed (2014); IHS Press Release (2014)
[116] Petrofed (2014); IHS Press Release (2014)
[117] DGH (2012)
[118] In terms of Finding and Development costs.
[119] Petrofed (2014); IHS Press Release (2014). Based on assumptions about the costs of supply which are influenced by geology, geography and infrastructure.

Figure 22: Prices Needed for New Commercial Production



Source: Petrofed (2014); IHS Press Release (2014); Compiled by Author from publicly available reports[120]

From the figure, it is evident that a gas price of at least $8.00/MMBtu is required to attract new (non-NOC) upstream investments. It is plausible that Indian NOC's could still invest at gas prices of $6-$7/MMBtu as discussed earlier, as they fall under the purview of government, and may require a lower discount rate or rate of return on investment.

Gas price reform could therefore lead to new upstream investments (potentially unlocking 30 Tcf of reserves at $8/mmbtu), with increasing significant additional potential as price is increased above this level.

However, new investments will also be contingent on the final decision on policy relating to fiscal regime for exploration and production. Should a Revenue Sharing Contract regime be adopted to replace Production Sharing Contracts, it is plausible that private sector/non-NOC investors would require a higher price than that reported in figure 22 in order to incentivise riskier offshore exploration.

It must also be noted that upstream exploration is subject to significant bureaucratic and procedural hurdles, as investors often have to wait to obtain various departmental and ministerial clearances even after winning blocks in auction rounds before work can actually commence. Santos and BHP Billiton, for instance, are two international exploration companies that are currently in the process of exiting their Indian assets for various reasons, which include bureaucratic delays. [121]

New investments in exploration are unlikely to be determined by the price alone, and are also contingent upon the implementation of reforms to the fiscal regime for exploration and overall investment framework.

[120] 'India's gas production to stagnate without pricing reforms' *Economic Times*, 11 June 2014, http://articles.economictimes.indiatimes.com/2014-06-11/news/50508397_1_gas-production-gas-demand-pricing-formula ; 'India's bold move on gas prices', *Petroleum Economist*, 3 July 2013, http://www.petroleum-economist.com/Article/3226455/Indias-bold-move-on-gas-prices.html

[121] Media reports suggests that this was also due to the fact that BHP-Billiton could not meet its investment commitments along with its Indian partner, GVK. See 'GVK, BHP likely to sell part of stake in blocks', Livemint – Wall Street Journal, 5 August 2011. Available at http://www.livemint.com/2011/08/05010243/GVK-BHP-likely-to-sell-part-o.html

5. Impact on the Main Gas Consuming Sectors

The impact of prices on the main downstream consuming sectors lies at the heart of the gas pricing reform issue, and will determine if reforms are sustainable in the long-term. There are two important sub-questions in this regard: first, will subsidies[122] continue? And second, how will the impact of a higher gas price on the subsidy bill be managed?

The first question has been partially addressed in Section 3.2. Specifically, the fertilisers sector represents a majority proportion of the electorate (over 50%) - low-income agricultural consumers - and subsidies to fertilisers are therefore likely to continue, although the mechanisms for delivery are being reformed. In power, the picture is not as clear, partly due to the fact that gas cannot compete with cheaper domestic coal, and also because some consumers (such as agriculture) are subsidised at the retail level. In general, there is no explicit subsidy on city gas prices but state governments have on occasion stepped in to prevent increases in the retail prices of CNG and PNG. We examine these three sectors further below.

5.1 Fertiliser Subsidies – Can the fertiliser sector bear a higher gas price?

The primary concern of policymakers in relation to gas price reforms is that a higher gas price will translate into a higher subsidy for fertilisers. This can be estimated at the 'macro' level and the 'micro' level. At the 'macro' level, a 2013 parliamentary report published by the Petroleum and Natural Gas Standing Committee estimated that a $1/MMBtu increase in the gas price translates to an increase in the cost of urea production of $25/tonne on average. For domestic urea production of about 22 million tonnes/year, this equates to adding $550 Million to the annual subsidy bill for every $1/MMBtu increase. There are also plans to add new urea manufacturing capacity of 9 million tonnes/year over the next few years, which equates to a further $225 Million for every $1/MMBtu increase in the gas price, or a total of $775 Million for every $1 increase. Assuming that the gas price rises to the level of $8/MMBtu, which has been the price estimated for stimulating new production, this would lead to an increase in the subsidy bill of roughly $2 Billion/year. In contrast, the 2015 Expenditure Budget[123] allocates roughly $6.4 Billion to subsidies for domestic urea and a further $2.05 Billion to subsidies for urea imports. If new domestic urea production offsets some of the import requirements for urea, the rise in the subsidy bill could plausibly be 'managed' if the subsidy for urea imports is redirected towards domestically manufactured urea.

An alternative to raising the retail price of urea that has been proposed is to finance the increase in subsidies through utilising the government revenues (from taxes and royalty payments) that would accrue from a higher gas price (as production will be valued at the higher price) to finance the higher subsidy bill. At the micro level, it is possible to examine the viability of this strategy using some broad estimates, in a two-step method. First, we use estimates of capital costs for Brownfield ('revival' and 'expansion'), Greenfield, and 'conversion' (fuel oil / low sulphur heavy stock based plants substituting gas for fuel oil or LSHS), as well as estimates of average energy consumption/tonne of urea.[124] These can be used along with assumptions on freight, margins and other costs to obtain the costs/tonne of manufacturing urea for each plant at different gas prices. The resulting estimates can be compared with the Maximum Retail Price of urea to obtain the average subsidy/tonne. These estimates can be scaled up on the basis of 22 million tonnes/year of domestic production of urea to obtain the total subsidy on domestic urea/year. Similarly, we use the five year average prices of spot imports of urea

[122] Subsidies here refer to payments that are separate from controlling the gas price at a low level.

[123] GoI (2015)

[124] We use assumptions from GoI (2007) Report of Working Group on Fertilizers for the 11th Five Year Plan, 2007.

($387.8/tonne) and long-term contracted imports ($131.4/tonne)[125] to calculate the total subsidy on spot imports (estimated at 6 million tonnes/annum) and long-term contracted imports (2 million tonnes/annum).

Table 7 contains the assumptions used for these estimates. The assumptions are derived from Jain and Sen (2011, p.44), Jain (2011, p.121) [126] and GoI (2013; 2007).[127]

Table 7: Estimated Build-up of Retail Price of Urea (Assumptions)

Average Energy Consumption (MMBtu of gas/tonne of urea)	
Substitution of FO/LSHS with gas in FO/LSHS based plants	24
Brownfield plants	21
Greenfield plants	21
Capital Related Charges ($/tonne)	
Substitution of FO/LSHS with gas in FO/LSHS based plants	50
Brownfield plants	102
Greenfield plants	110
Weighted Inland Average Freight ($/tonne)	10
Average Margin ($/tonne)	5
Conversion Charge ($/tonne)	20
Maximum Retail Price (Subsidised) ($/tonne)	88.50

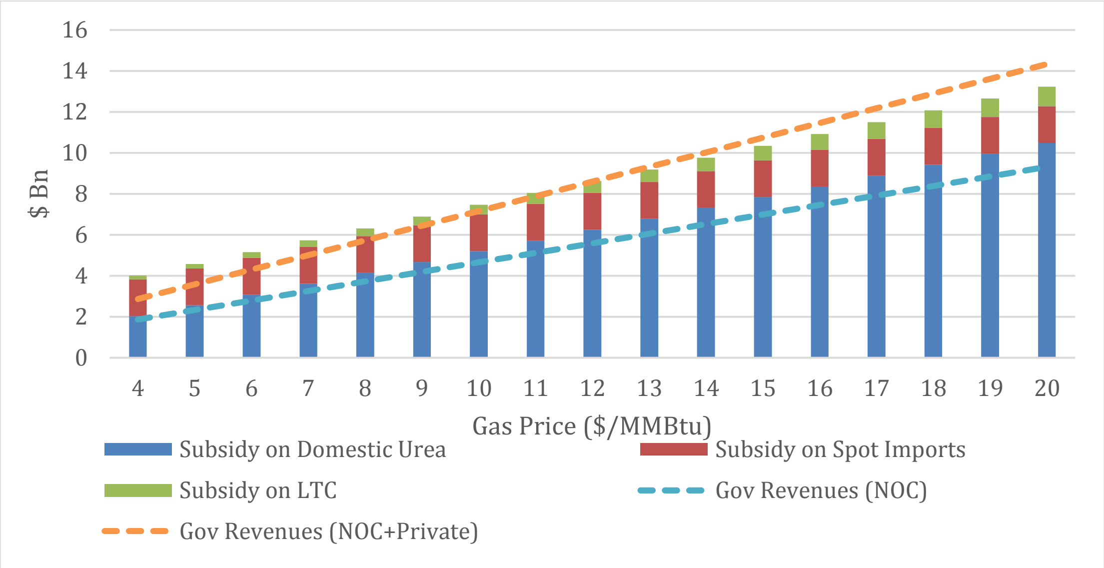
Source: Jain and Sen (2011, p.44); Jain (2011, p.121); GoI (2012b); GoI (2007, pp.180-3)

We estimate the revenues that will accrue from gas production at different gas prices. The royalty rate for offshore gas is 10%, and the corporate tax rate is roughly 33%. By valuing production at a range of different gas prices and applying these levies, it is possible to obtain total government revenues that will accrue at different gas prices. We do this based on estimates of expected production for 2014 (shown earlier in figure 18). We carry out two separate estimates, one for NOC production targets, and the other for NOC plus private sector production targets, as we are interested in ascertaining how much of a role private sector production will play in managing the subsidy bill.

In the final step of this analysis, we map graphically the total subsidy bill against the total government revenues at a range of gas prices. We do this for NOC production, and for NOC plus private sector production. We also do this for all three plant types (FO/LSHS conversions, Brownfield, and Greenfield).The results of this analysis are presented in Figures 23 to 25.

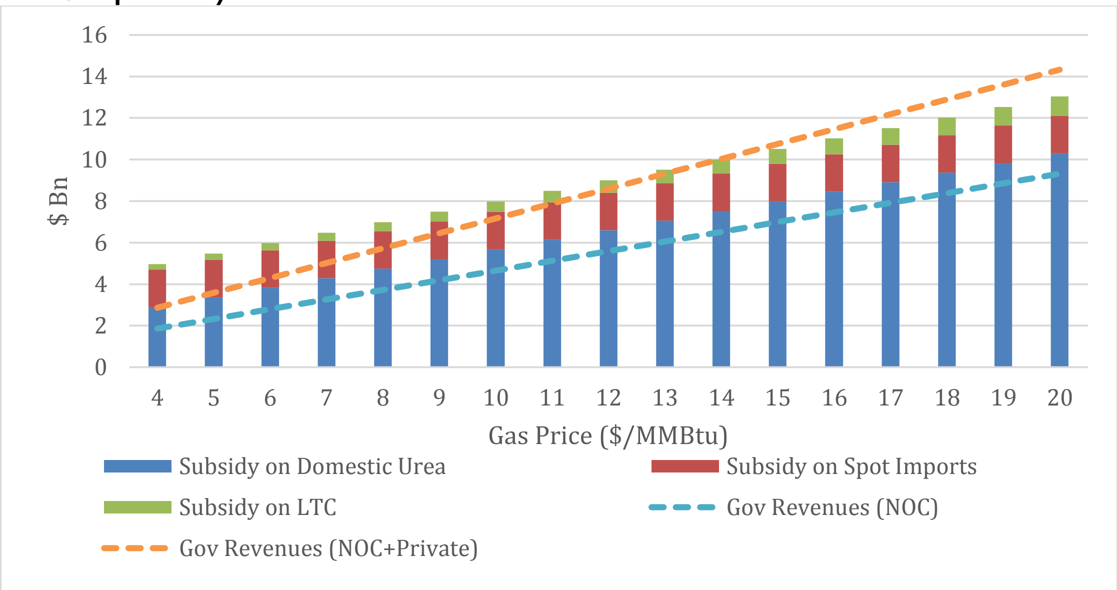
[125] The five-year averages are based on data from the Report of the Working Group Fertilizers for the 12th Five Year Plan, 2012. (GoI, 2012b)
[126] Based on GoI (2007),*p.*180
[127] GoI (2013b)

Figure 23: Government Revenues (Taxes & Royalty) versus Total Subsidies - Substitution of FO/LSHS with Gas as Feedstock in FO/LSHS based Urea Plant



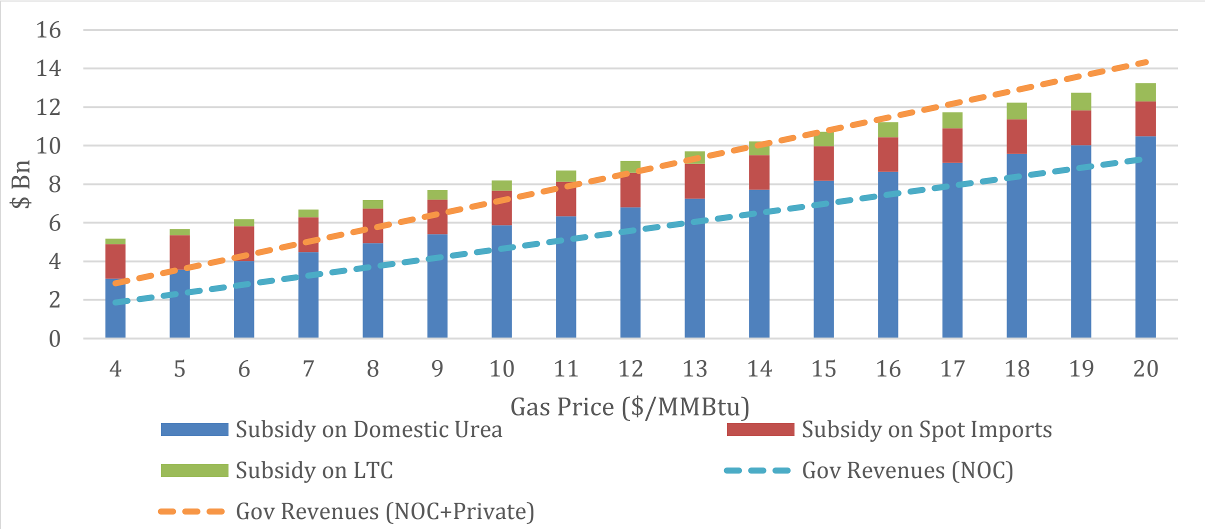
Source: Author's estimates

Figure 24: Government Revenues (Taxes & Royalty) versus Total Subsidies - Brownfield (Revival / Expansion) Urea Plant



Source: Author's estimates

Figure 25: Government Revenues (Taxes & Royalty) versus Total Subsidies - Greenfield Urea Plant

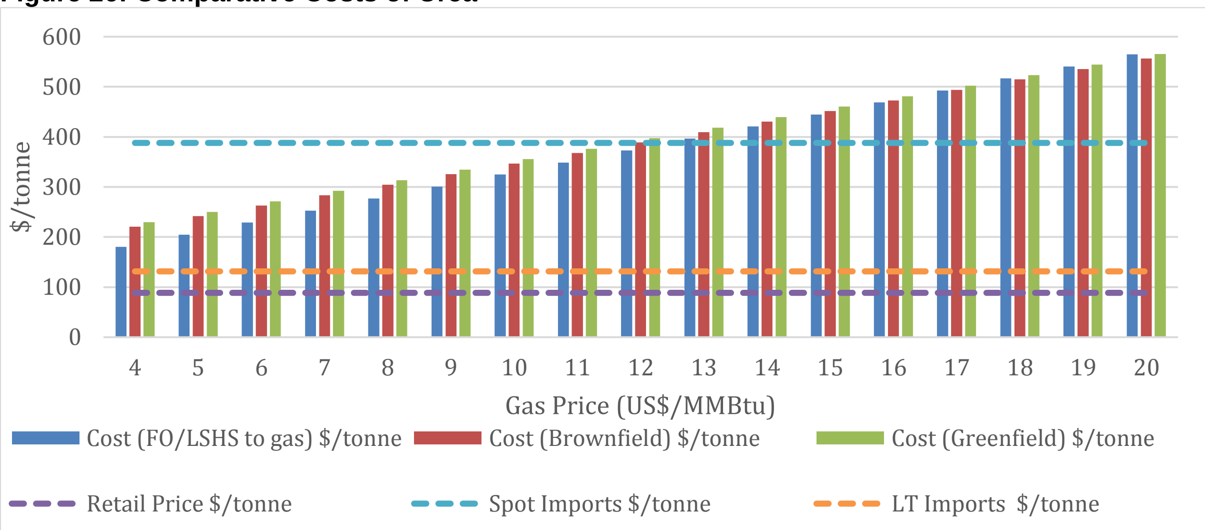


Source: Author's estimates

Figures 23-25 show that it is unlikely that the total subsidy bill (domestically manufactured plus imported urea) can be financed entirely from government revenues based only on NOC production targets. At higher production levels (NOC plus private sector targets, or an equivalent increase in NOC production), it is possible for urea subsidies to be completely offset, at gas prices of $9-$11(in figure 23) for existing plants. However, the 'offset' will be at relatively higher gas prices for Brownfield and Greenfield plants (around $13).

An alternative strategy to 'manage' the subsidy bill would be to replace spot purchases of urea with long-term contracted imports. This would require a longer-term strategic reform of fertiliser sector policy.

Figure 26: Comparative Costs of Urea



Source: Author's estimates

Figure 26 above shows the potential savings from this alternative strategy by mapping out the price of urea in $/tonne at different gas prices, and superimposing the prices of spot purchases of urea imports, long-term contracted imports, and maximum retail price (subsidised price) of urea.[128]

In summary, the fertiliser (urea) subsidy can be completely offset by the increase in government revenues that will accrue from production being valued at a higher price, but only if both NOC and private sector production targets are met, and at gas prices of approximately $9-$11 /MMBtu. However, any increase in gas price above current levels will reduce the absolute size of government subsidies through higher royalties and taxes; this refutes the claim that relying on some average of international gas reference prices does not lead to a breakeven on subsidies, as the fact that the net impact on government finances can be reduced is equally important.

5.2 Impact on the Power Sector

The Indian power sector represents the country's 'mixed' economic structure- where a small but growing number of market-oriented systems of power production, distribution and trading exist alongside centrally controlled institutions. On the one hand, the merit-order dispatch system, where the cheapest fuels are prioritised in generation, is predicated on a model encouraging price competitiveness in generation. However, on the other hand, gas is sold at controlled prices which are three to four times lower than on the international market – and despite this is unable to compete with coal. Power is also a state matter – states have autonomy over power policy in India. Pricing (tariff) decisions of distribution utilities are therefore determined at the state level, and tariffs have remained 20% below the cost of power on average (Figure 11). This heterogeneity precludes a straightforward assessment of the potential for gas in power; however, it is possible to obtain some estimates from a broad comparison based on relative (average) costs of electricity generation.

The average selling price of power has been estimated at around Rupees (₹) 3.2/kWh, and the fixed cost at ₹1.35/kWh.[129] Every $1/MMBtu increase in gas prices leads to an increase of $1.3/MMBtu in the delivered price of gas to power, and an increase of roughly ₹0.45/kWh in the variable cost.[130] Figure 27 depicts the results mapped against the average costs of power from coal, with the cost of electricity measured in ₹/kWh on the left vertical axis and the delivered price of gas in $/MMBtu on the right vertical axis. The figure shows that gas is uncompetitive with domestic coal, and becomes uncompetitive with imported coal at a gas price of between $5.20-6.20/MMBtu.

This contradicts the optimistic official assessments of the future potential for gas in power. At a higher gas price, the difference will either need to be passed through to consumers or subsidised. At a gas price of $8.20/MMBtu (based on the estimated price of $8/MMBtu for domestic production), the cost of power rises to roughly ₹5/kWh. For India's output from gas-fired generation of 85.86 Billion kWh, this translates into an increase of ₹153 Billion or $2.5 Billion. If this were passed through to all consumers then, spread across total annual consumption of 900 Billion kWh, it would lead to a rise of approximately 5% in the price of electricity. If the pass-through were limited to total consumption of gas-fired power (approximately 86 Billion kWh), the percentage would be far higher and potentially unaffordable to even commercial consumers, at 55%.

The prospects for gas would be improved if a concerted effort was aimed at reforming electricity pricing for each fuel in line with environmental goals. There is no explicit carbon pricing regime for power, apart from a 'coal tax' of ₹200/tonne ($3/tonne) the proceeds of which are meant to go into a clean energy fund. For steam coal production of approximately 526 Mt[131], this should pull in revenues

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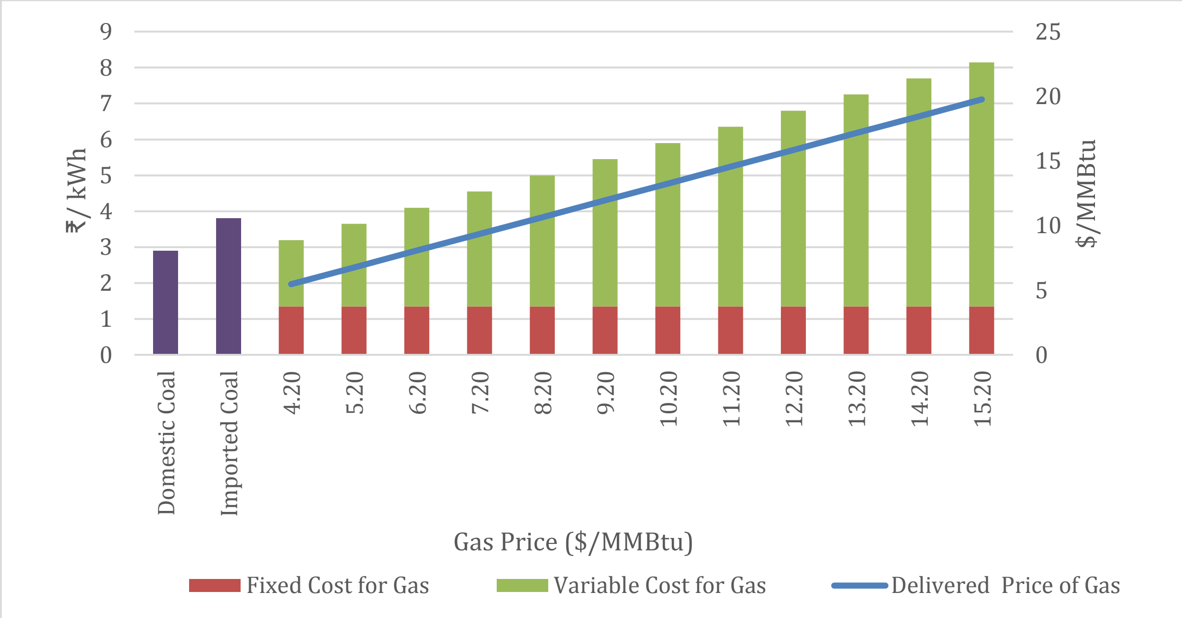
[128] All figures and data are estimates meant to provide a broad picture of possible solutions to the price-subsidy dynamic.
[129] This corresponds to a capital cost of ₹35-45 Million/MW for a gas based power station (ICRA, (2014); CRISIL, (2010). Jain (2011, p.44) estimates that this fixed cost is for a medium sized power plant.
[130] GoI (2013a)
[131] World Coal Statistics http://www.worldcoal.org/resources/coal-statistics/

of $1.58 Billion/annum. However, it is unclear in what manner the proceeds from the fund are to be utilised.

Figure 27: Estimated Cost of Power from Gas versus Coal



Source: Author's estimates

In practice, as electricity policy is regulated by Indian states, it is difficult to estimate how higher prices may be dealt with. It is potentially easier to administer a federal subsidy uniformly preventing price increases, than gain a consensus on tariff pass-through at the state level. However, the question remains how any subsidy would be financed, in addition to the fact that it would contradict the government's current fiscal stance.

Given the current structure of the electricity generation sector, and the lack of a carbon price, gas becomes uncompetitive with coal at prices between $5.20-$6.20/MMBtu. An increase in the gas price to $8/MMBtu could potentially lead to a 5% rise in power tariffs if the increase is spread across total units of consumption (from all fuel sources).

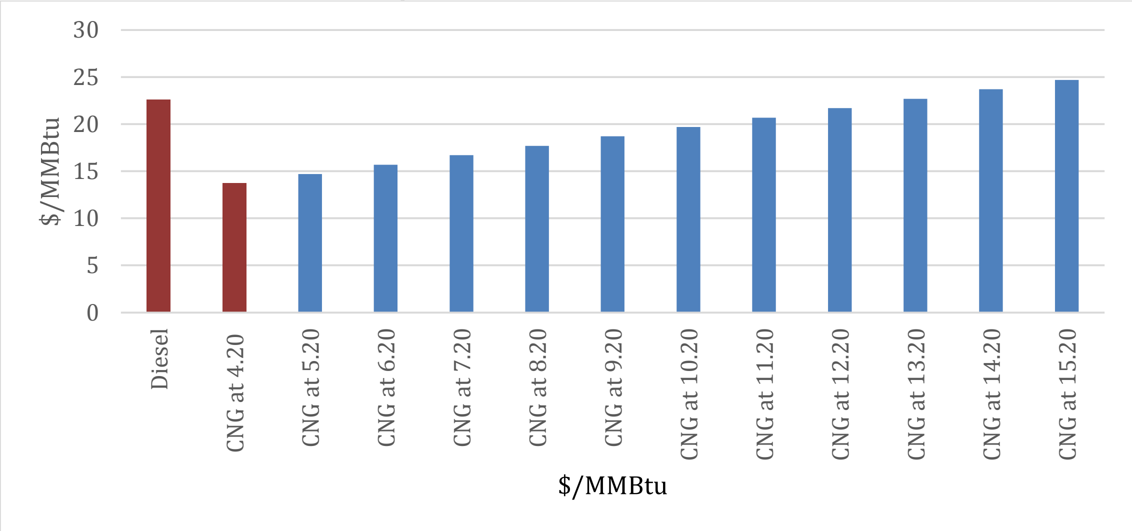
A potential 'pocket' of demand for gas in power is in captive generation, estimated at around a third of India's total generation capacity (of roughly 250 GW). The restructuring and ongoing reform of India's power generation sector which designated power trading as a separate activity and allowed the operation of 'merchant power plants[132], combined with domestic gas supply shortages and the downward trend in LNG import prices, could lead to a short-term rise in gas (LNG) demand in this sector. However, there are two factors which suggest that this is unlikely to continue in the longer term. First, the viability of the power trading model in the generation sector is being severely tested by politics, as seen in the recent decision of Delhi's new state government to cut power tariffs by 50% for certain consumers, on the basis that the procurement of power from the short-term market by utilities has inflated power bills for consumers. Second, the government has announced plans to double India's coal output by the end of the decade, and to reduce dependence on imported coal. Even if domestic coal production targets are not met, all indications (US energy production combined with EU carbon emissions reduction targets) suggest that coal may be cheaper to obtain on the international market in the long term.

[132] Power plants producing electricity for sale to utilities.

5.3 Impact on the City Gas Sector

The outlook for gas in the city gas sector is arguably more favourable than in power. As discussed in Section 3.2.3, Piped Natural Gas (PNG) for households and Compressed Natural Gas (CNG) for transportation are fast-growing segments, on the back of growing urbanisation and greater attention towards curbing urban air pollution (in public transportation). However, the biggest factor that has shaped the outlook for city gas is the recent reform of petroleum product pricing, which has improved the competitiveness of city gas.

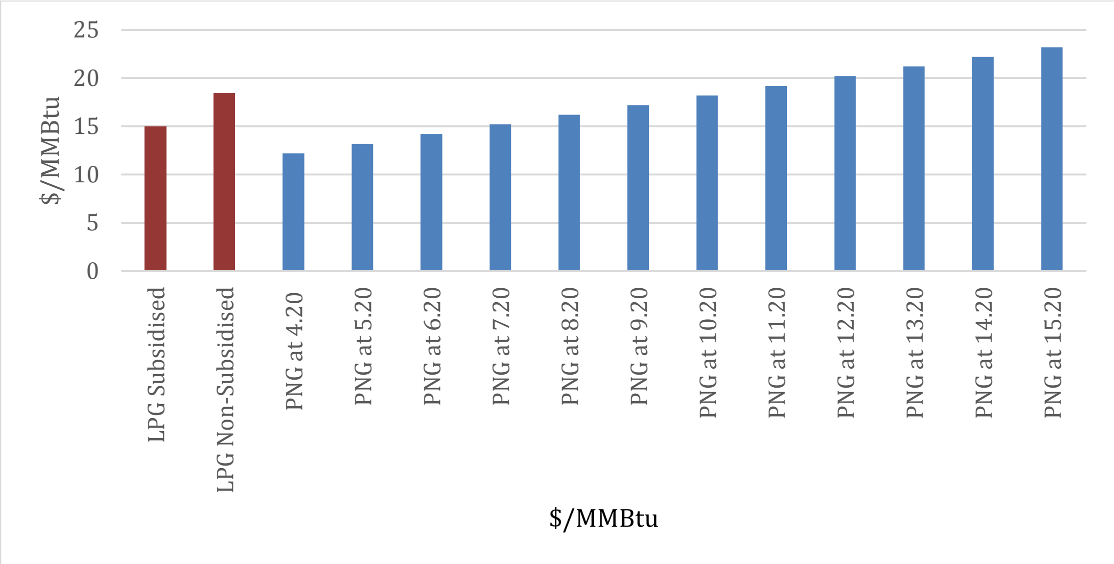
Figure 28: Estimated Price of Compressed Natural Gas versus Diesel



Source: Author's estimates based on ICF (2014)

Figure 28 shows the competitiveness of CNG at different gas prices with diesel – its main substitute. Diesel prices were liberalised in October 2014 after a sustained period of phasing out subsidies. The potential for city gas lies in an increasing number of cities adopting CNG in public transportation. Whilst the original policy motivation for CNG was environmental, the liberalisation of diesel prices has also made it economically viable, even at higher gas prices.

Figure 29: Estimates of Price of Piped Natural Gas versus Subsidised and Non-Subsidised LPG[133]



Source: Author's estimates based on ICF (2014)

Figure 29 shows the competitiveness of PNG with LPG, its main substitute in city gas for households. The supply of subsidised LPG is capped at twelve 14.2 kg cylinders/household, whereas non-subsidised LPG (for commercial users) is sold at market prices, which are frequently adjusted. The estimates in Figures 28 and 29 are based on prices and taxes in Delhi, but they differ across different states. Both figures suggest that city gas can bear higher prices and remain competitive with the main substitutes. The absence of price controls on city gas distribution entities suggests that higher prices could be passed through.

However, the continuing emergence of a 'market' in city gas is contingent upon the amount of gas that can be absorbed in this sector and its future expansion in demand. One of the main constraints to this is infrastructure. There has been a significant amount of investment into the expansion of city gas infrastructure by companies such as GAIL – indicating that city gas distribution entities believe that there is a potential market for PNG, backed by a push from the government towards the development of a 'national gas grid'.

There are currently 15,000 km of pipelines in India, and a further 15,000 km planned or in the early stages of construction, of which 400 km is to be constructed through Public Private Partnerships. However, these plans have been faced with two problems – first, delays in acquisition of the right to use land (due to public opposition), and second, a 'chicken and egg' problem where the absence of 'anchor' customers for gas has made companies reluctant to begin construction on pipelines even after the tenders have been awarded. Table 8 shows the status of these planned pipelines.[134]

[133] The break-up of CNG prices in $/MMBtu was obtained from ICF (2014), based on prices in Delhi which equate to ₹38.15/kg. They include transportation charges ($0.30), marketing margins ($0.10), taxes ($2.10), network charges, compression charges, and selling, general and administrative charges and other margins ($5.90). The same applies to PNG, based on prices in Delhi of ₹25.50/scm.

[134] Sen (2012) contains a map of existing pipelines. Details of existing pipelines can be found at the Petroleum Planning and Analysis Cell http://ppac.org.in/WriteReadData/userfiles/file/NG_pipeline.pdf

Table 8: Status of Planned Pipelines

Pipeline	Status & Company	Length (km)
Category 1	Authorisations granted	
Jagdishpur-Phulpur-Haldia	GAIL	2,050
Shadhol-Phulpur	RGPL	312
Kakinada-Vizag-Srikakulam	APGDCL	391
Category 2	Absence of ‘anchor’ customers	
Mallavaram-Bhopal-Bhilwara via Vijaypur	GITL	2,042
Mehsana-Bhatinda	GIGL	2,052
Bhatinda-Jammu-Srinagar	GIGL	725
Surat-Paradip	GAIL	2,112
Category 3	Authorisation pending	
Ennore-Nellore		220
Ennore-Thiruvallur-Bengaluru-Puducherry-Tuticorin		1,175
Ranchi-Talcher-Paradip		520
Barauni-Guwahati-Agartala		1,300
Haldiya-Paradip/Srikakulam		~500-700
Category 4	In progress or stalled	
Kochi-Koottanad-Bangalore-Mangalore	GAIL	1,062
Spur lines to Dadri-Bawana-Nangal	GAIL	100
Spur lines to Chhainsa-Jhajjar-HIssar	GAIL	193
Spur lines to Dabhol-Bangalore	GAIL	410

Source: GoI (2014c)

There are two pathways to the wider economic impact of a potentially higher gas price – either higher subsidies, or, a rise in prices. In fertilisers, the increase in the subsidy bill from the manufacture of 22 million tonnes/year of urea[135] at a domestic gas price of $8/MMBtu amounts to approximately $4 Billion/year. In power, however, a gas price of approximately $8/MMBtu used to produce 86 Billion units of gas-fired electricity (10% of total generation) would amount to a subsidy of ₹153 Billion/year ($4.55 Billion). Collectively, these subsidies could potentially add 16% to the total budgeted subsidy bill (including food, fertilisers and all other subsidies) for 2015. As discussed, there is the potential for some of this to be met through increased government revenues.

A Confederation of Indian Industry study in 2014[136] estimated the impact of a pass-through of gas prices to consumers on the Wholesale Price Index (WPI) using the formula: Impact on WPI = % increase in price of item * Weight of item in WPI. The increase in the WPI averaged 6% in 2013-14.[137] Fertilisers (urea) and power have weights of 1.58% and 3.45% in the WPI.[138] In fertilisers, the 2010 increase of the domestic gas price from $1.79/MMbtu to $4.20/MMbtu was not fully passed through to the retail price of urea, although there have been a couple of upward revisions. Therefore, if we

[135] We use the estimates for FO/LSHS plants converted to gas. The manufacturing costs for Greenfield plants would be higher.
[136] ICF (2014) ‘CII Report on Impact of Domestic Gas Price Increase on End Consumer Sectors’, *ICF International*, July 2014.
[137] Reserve Bank of India. Available at http://rbi.org.in/Scripts/AnnualReportPublications.aspx?Id=1134
[138] Office of Economic Advisor, Government of India. Available at http://www.eaindustry.nic.in/wpi_2004_05/Annex1.pdf

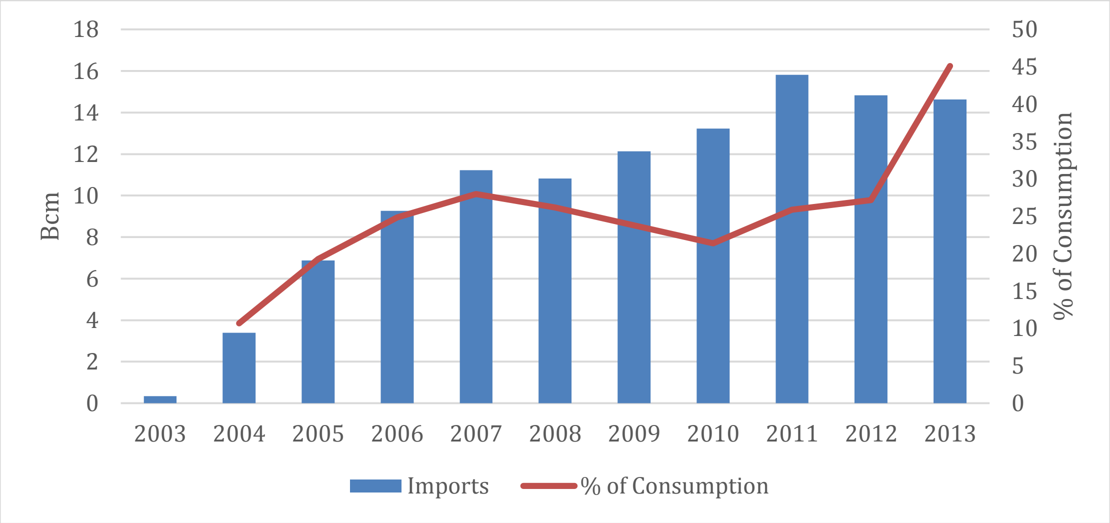
assume a full pass-through of cost[139] to the consumer price of urea, this translates into an increase in the WPI of 3.37% at a gas price of $8/MMBtu. If we assume a partial pass-through of cost to the retail price of urea (with the remainder met by subsidies), this would translate into a lower increase in the WPI of 1.66%. For the power sector, an increase in the gas price to approximately $8/MMBtu would translate into an increase in the WPI of approximately 2% if the price rise was applicable only to consumers of gas-based electricity, but to a lower increase of 0.17% if the price rise was made applicable to all electricity consumers.

[139] We assume that the difference between $1.79 and $4.20/MMBtu was fully passed on but not the increase from $4.20 to $8.40/MMBtu.

6. Outlook for Imports

As shown in Section 3, most projections of domestic gas production converge to 100 – 112 Bcm/year by 2030-35. The demand for (or potential consumption of) gas can be placed at roughly 200 Bcm/year around the same time period. The potential for imports can therefore be estimated at 100 Bcm/year. Figure 30 shows that India's LNG imports have risen steadily over the last decade (the dip in imports as a percentage of total gas consumption in 2010 was due to an increase in the total availability of domestic gas for consumption from private sector production in that year).

Figure 30: India LNG Imports, 2003-2013



Source: BP (2013); PPAC (2014)

There are two constraints to the fulfilment of this import potential.

The first is the ability of India's infrastructure to import greater volumes of LNG, as this import potential translates into a requirement for 140 mtpa of regasification capacity by 2030-35. There are several LNG regasification terminals at various stages of operation, planning or construction. These are shown in Table 9. The terminals in operation are Dahej (96% capacity utilisation), Hazira (56% capacity utilisation), Dabhol (30% capacity utilisation) and Kochi (less than 2% capacity utilisation).[140] It is evident that India (in the most optimistic scenario) will have built only 83 mtpa of total regasification capacity by 2030 – which falls short of the capacity required. Construction times have typically been subject to long delays over factors such as the acquisition of land and planning permission, the absence of 'anchor' customers located within the geographical vicinity of terminal infrastructure, and delays in building pipelines (for instance, the pipelines for the Kochi terminal have yet to be completed). Legislation is currently being tabled in Parliament on streamlining procedures for the acquisition of land for infrastructural projects, and the current government has reiterated its plans to facilitate the expansion of natural gas infrastructure (pipelines) and streamline the procedures for private investments. However, this legislation is being held up in the Upper House (Rajya Sabha) where the ruling government lacks a majority. Two outcomes are likely: first, that the government obtains parliamentary consensus on a 'watered down' version of these measures. Or second, that

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[140] GoI (2014c)

these issues continue to be unresolved until 2016, when scheduled Rajya Sabha elections could return the ruling government to the Upper House with a majority.

Table 9: Planned Regasification Terminals (Capacity mtpa)

Regas. Terminal	2012-13	2016-17	2021-22	2026-27	2029-30
Dahej	10	15	15	15	15
HLPL Hazira	5	10	10	10	10
Dabhol	5	5	5	5	5
Kochi	2.5	5	10	10	10
Ennore	-	5	5	5	5
Mundra	-	5	10	10	10
Kakinada (FRSU)	-	5	5	5	5
Gangavaram	-	3	3	3	3
East Coast Terminal	-	2.5	5	10	10
West Coast Terminal	-	-	5	10	10
Total Capacity	**22.5**	**55.5**	**73**	**83**	**83**
At 70% Utilisation	**15.8**	**38.8**	**51.1**	**58.1**	**58.1**

Source: BCG (2014)[141]; PNRGB (2013)[142]

The second constraint to India's LNG potential is the ability of buyers to contract for these volumes in the international market. This is contingent to some extent on price. India is amongst the world's top five LNG importers, with 13.3 mtpa in 2013, out of total available supply of roughly 240 mtpa.[143] 83.8% of the Indian imports were from Qatar, with the remainder from Nigeria (6.8%), Egypt (2%), Algeria (0.9%) and Yemen (4.6%), with single cargoes from Russia, Brunei, Norway and France.[144] Roughly 60% of this was on long term contracts and the rest on a short term or spot basis.[145] Given the expectations of a soft market for LNG by the end of this decade, with new volumes of roughly 116.7 mtpa potentially added to world supply by Australia, USA, Papua New Guinea, Russia, Angola, Algeria and Indonesia[146], as well as the lagged effect of falling oil prices on oil-linked LNG supply contracts, it is plausible that Indian buyers would manage to contract volumes at prices acceptable to end-consumers.

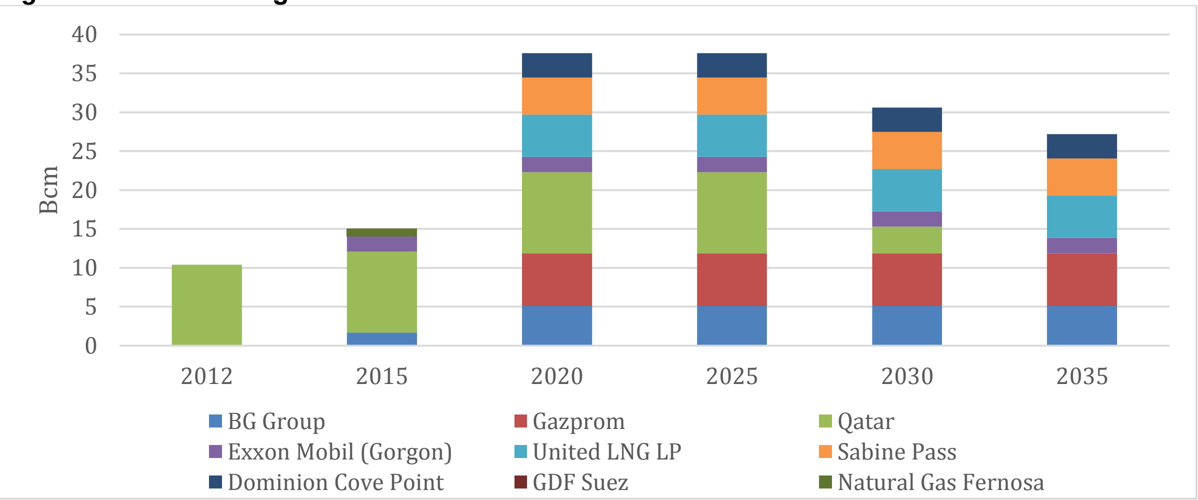
[141] BCG (2014)
[142] PNGRB (2013)
[143] BCG (2014)
[144] Gas Matters (2014)
[145] BCG (2014)
[146] BCG (2014)

Table 10: LNG Long Term Contracts

Importer	Exporter	Volume (mtpa)	Term (Years)	Indicative Starting Year	Contract Signing Year
GSPC	BG Group	1.25	20	2015	2013
GSPC	BG Group		20	2017	2013
GSPC	Gazprom	2.5	20	2016	2011
Petronet LNG	Ras Laffan LNG Co Ltd	5.0	25	2004	N/A
Petronet LNG	Ras Laffan LNG Co Ltd	2.5	25	2009	N/A
Petronet LNG	Exxon Mobil	1.5	20	2015	2009
Petronet LNG	Gazprom	2.5	25	N/A	2011
Petronet LNG	United LNG LP	4.0	20	2020	2013
Gail India	Sabine Pass Liquefaction Company	3.5	20	2017/18	N/A
Gail India	Gazprom	2.5	20	2018/19	N/A
Gail India	US Dominion Cove Point	2.3		2018/20	N/A
Gail India	GDF Suez	0.36	3	2013	N/A
Gail India	Natural Gas Fenosa	0.72	2	2013	N/A
Indian Oil		2.5	25		
Total (Mtpa)		**31.13**			
Total (Bcm)		**45.66**			

Source: BCG (2014)

Figure 31: India's Long-Term LNG Contracts



Source: Author's estimates from Table 10

GAIL recently scrapped a tender for the construction of nine LNG ships, which were presumably meant to carry its LNG supplies contracted from the US, over concerns related to the Indian government's 'Make in India' initiative which encourages local content requirements for domestic

manufacturing projects. India's shipyards currently lack the technology to construct these carriers and could not attract foreign investors interested in sharing technology.[147]

Table 10 above shows estimates of India's current long-term contracts for LNG supplies –which amount to approximately 46 Bcm/year at present, and figure 31 graphs these volumes to 2035. A recent strategy has been for Indian LNG importers such as GAIL to enter into agreements with importers from other importing nations such as Japan (Chubu Electric) for the joint procurement of LNG supplies. GAIL also has 'Master Sales Purchase Agreements' with 25 LNG suppliers for the import of spot cargoes, while Petronet LNG, another major Indian LNG Importer, has 30 such agreements. GAIL has also entered into an agreement with Natural Gas Fenosa to collaborate across the LNG value chain.[148]

6.1 Pipeline Imports

India has long attempted to secure agreements for the import of gas through cross-border pipelines – notably, long-drawn out diplomatic efforts have gone into attempting to bring the Turkmenistan-Afghanistan-Pakistan-India (TAPI), Iran-Pakistan-India (IPI) and Myanmar-Bangladesh-India (MBI) projects into operation. India failed to implement the MBI project, and IPI remains unresolved over disagreements on price. More recently, India has been diversifying away from Iranian supplies (both oil and potential gas) because of concerns over the sustainability of ongoing negotiations between Iran and the P5+1 countries. A particular concern is the impact of a future reinstatement of sanctions – India faced serious problems in obtaining and paying for its oil supplies from Iran during the last round of sanctions.

TAPI, which was conceived in 2005 but has run into long delays, appeared to have achieved a breakthrough in 2013, with backing from the US, which pushed for an alternative to India pursuing the IPI pipeline (and collaboration with Iran). Chevron allegedly offered to take on the contract to build and operate the pipeline, and a gas sales and purchase agreement was signed with Turkmenistan and Pakistan, with the price to the Indian border estimated at \$13/MMBtu. However, by 2014 Chevron was reported to have pulled out. In 2014 Total SA expressed interest in leading the project consortium but also pulled out. Both companies reportedly pulled out over Turkmenistan's refusal to allow foreign companies an equity stake in the Galkynysh field in return for leading the consortium of NOCs involved in the project. In the meeting of the 20th Steering Committee on TAPI in February 2015, India urged Turkmenistan to relax its legal restrictions on foreign equity in order to secure an international partner to lead the consortium in building and operating the \$10 Billion pipeline. The pipeline was meant to be operational by 2018, running from Galkynysh to Herat and the Kandahar province of Afghanistan, through Pakistan (Multan via Quetta) ending at Fazilka (Punjab) in India. TAPI would deliver 14 Bcm/year of gas to India and Pakistan and 5 Bcm/year to Afghanistan.[149] The indications point to continued efforts by the new Indian government to see the project through, but the ball currently appears to lie in Turkmenistan's court, as any potential Consortium Leader is likely to seek an equity stake in its reserves as compensation for carrying out the project.

The lack of previous success has not affected India's optimism on pipelines – in 2014, India and Russia were reportedly in talks to construct an overland pipeline to bring hydrocarbons to India via north-west China. However, given India's history of pipeline negotiations, potential security issues, and geopolitics, this project too is likely to run into procedural and pricing hurdles, not to mention logistical constraints, before any real progress can be made.

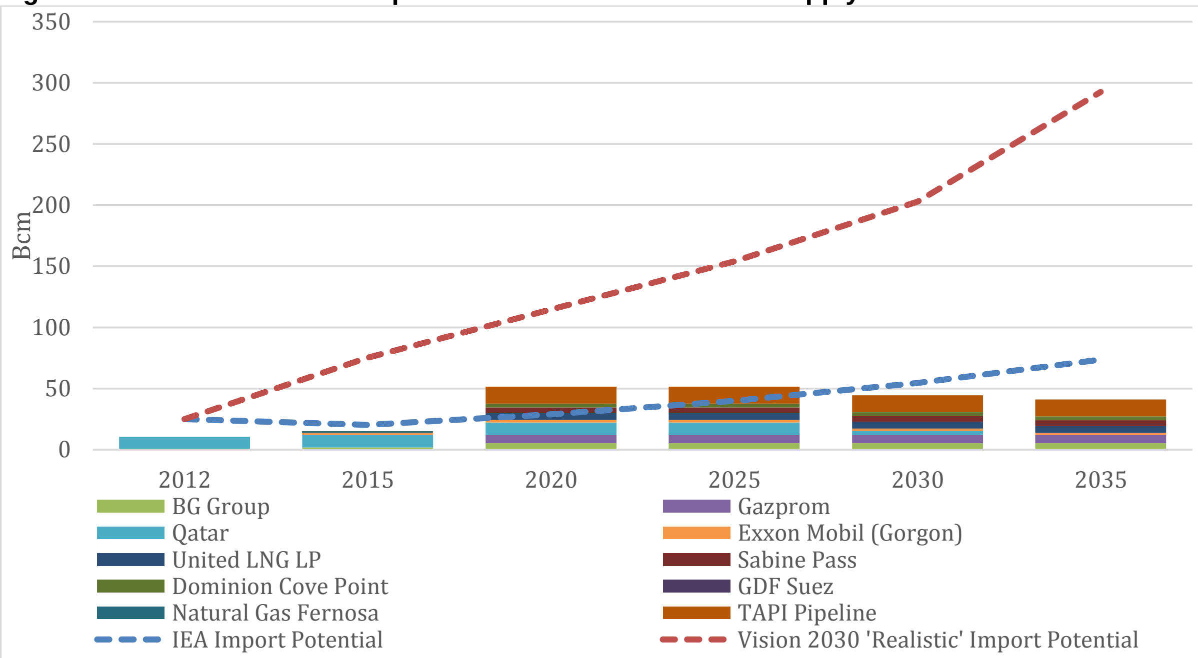
[147] 'Gail scraps failed LNG ship tender as Make in India caveat deters foreign shipbuilders', Livemint, 19 February 2015 http://www.livemint.com/Companies/rqNr4vv3TGGCKKPi3lg89H/Gail-scraps-failed-LNG-ship-tender-as-Make-in-India-caveat-d.html

[148] GoI (2014c)

[149] 'TAPI pipeline: India asks Turkmenistan to ease rules' *Economic Times*, 11 February 2015.

Another pipeline option that has been explored is a deep-sea route, which was proposed as a solution to the security concerns associated with overland routes. The Oman-India pipeline could supply 8 Tcf of gas to India over 20 years, through a 1,300 km pipeline laid below the sea-bed. It could potentially connect the Middle East Compression Station near Oman with a receiving terminal near Gujarat on India's west coast. The estimated cost is $5 Billion and it was reported that the project could be executed in about five years. An attraction of this option is its more direct route and proximity to gas sources in the Middle East and thus its lower landed cost.[150] However, no headway has been made on this option thus far.

Figure 32: Potential for LNG Imports versus Contracted LNG Supply



Source: Author's estimates[151]

Figure 32 maps India's long-term contracted imports and TAPI supplies against the potential shortfall of gas from domestic production in the 'conservative' (IEA New Policies Scenario) and 'optimistic' (Vision 2030 'Realistic' – Indian Petroleum and Natural Gas Regulatory Board[152]) scenarios described in Section 3. Based on the IEA projections, the potential shortage of gas after accounting for these contracted is around 30 Bcm in 2035. However, the 'Vision 2030 Realistic' projections indicate a far higher potential, although as discussed earlier, it is very difficult to justify this in the absence of clear pricing signals. Actual import potential is likely to be somewhere between these two poles. A reading of figure 32 against the IEA Import Potential scenario also indicates that India could face a relatively soft market (oversupply) in 2020, unless TAPI is further delayed.

[150] 'Oman-India gas pipeline a most promising option' *Economic Times,* 19 November 2014
[151] Long-term contracted LNG may not include all contracts including those under negotiation as accurate data was difficult to obtain. It also does not take into account potential new supply – for instance from East Africa.
[152] As discussed in Section 3, this adjusts the 12th Five Year Plan forecasts downwards to obtain more 'realistic' estimates.

7. Summary and Conclusions

This paper has discussed a fundamental problem in assessing the potential 'market' for gas in India, and by extension its role in global gas markets. The Indian gas sector is broadly characterised by two moving parts: one which has prices and quantities set by the Indian government, and another which utilises gas at market (LNG import) prices. Additionally, there is some overlap between the two, further complicating attempts to assess them as separate markets. The lack of a clear pricing signal therefore makes it difficult to determine future levels of demand or consumption. Reforms to the pricing of domestic gas could potentially change the Indian gas landscape by making price signals clearer. However, this paper has shown that the new gas price formula continues to be predicated around managing the price level, rather than establishing a market-related basis for price formation. The analysis of the new gas pricing formula reflects a contradiction in reasoning: the Committee which recommended the new formula argued for a shift away from oil-linked Japan Customs-cleared Crude (JCC) prices due to the declining relevance of oil-linked mechanisms, while including (lower) Russian net-back domestic gas prices which are arguably, if indirectly, also oil-linked.

The nature of the gas price reform thus far implies the continuation of price level as the main focus, unless there is

: a reorientation of policy towards a longer-term goal for the role of gas in the Indian economy relative to coal and oil, and
: a roadmap for gas price reform which reflects the dynamics of the Indian gas market, rather than focusing exclusively on regional dynamics in other gas markets.

This is particularly relevant as there is no 'global gas price' - although in 2015, European spot and Pacific LNG prices have been converging and are also closer to Henry Hub prices than in the 2011-15 period; but this paper has argued that Indian gas prices arguably need to depend on Indian market conditions. Against this background, this paper has investigated three main questions relating to the recent gas pricing reform in India.

First, could gas pricing reform reverse the recent decline in domestic production?
Second, could it lead to new upstream investments in gas?
And finally, what is the impact of the reform on downstream consuming sectors?

A review of existing reserves shows that the decline in domestic production is unlikely to be fully reversed, although it is plausible that production could be increased (by roughly 18Bcm/year) through prices of approximately $6-7.15/MMBtu. However, this would have to come from NOC (ONGC) rather than private sector production in the absence of a significant new 'giant' discovery, as ONGC appears to hold the largest proportion of gas reserves as well as Petroleum Exploration Licenses. A review of data on production costs and breakeven prices (based on existing studies) shows that gas prices of $8/MMBtu could potentially incentivise 30 Tcf of additional reserves to be brought into production, contingent upon reforms to the fiscal regime for exploration. However, new investments in exploration are unlikely to be determined by the price alone (as calculated by the current formula), and are also contingent upon the implementation of reforms to the fiscal regime for exploration.

This paper has also set out the dynamics of the demand for gas in India, and an analysis of the prices at which any sort of gas 'market' could begin to develop in the various gas consuming sectors. It has described a two-tier structure of demand under the government's current policy of rationing gas to prioritised sectors. The demand for gas has long been set (through allocation) in the fertilisers sector – which has until recently sat at the top of the first tier, where there is potentially latent demand. The underlying policy concern behind this has been the impact of higher prices on retail fertiliser prices. This paper has investigated the extent to which higher revenues from royalties and corporate taxes on

the back of a potentially higher gas price could be used to finance higher subsidies on fertilisers in the medium term, and the viability of a re-orientation of fertiliser policy towards long-term contracted fertiliser imports beyond this. The analysis shows that this strategy would only work if gas prices rose to $9-11/MMbtu, and only if both NOC and private sector production targets are met. This shows the existence of a 'circular problem' to which the current pricing and fiscal regime does not appear to provide any solution. However, any increase in the domestic gas price would reduce the net cost of the subsidy on urea through increases in tax and royalty receipts on producing gas fields, as royalty and tax take rises faster with the gas price than the subsidy.

Another important finding on the impact of gas pricing reform on downstream sectors is the universally negative impact on the power sector due to the absence of carbon pricing or equivalent incentive mechanism encouraging the use of gas (to displace coal). The analysis has shown that gas is uncompetitive with domestic or imported coal at gas prices above $5.20-$6.20/MMBtu (on a variable cost basis for existing plant) under the current design of the power generation sector. This paper has broadly estimated the impact of a pass-through of higher electricity prices to the entire consumer base (representing 900 Billion kWh) and to gas-fired consumption only (86 Billion kWh), although neither of these is likely given the heterogeneity of power sector policy across Indian states. State regulations on third-party access have meant that gas at higher prices often cannot be sold to price inelastic consumers. More generally, the future demand for gas in power generation may have been vastly overestimated by official forecasts which portray the power sector as the main driver of gas consumption to 2030. The future of gas in power generation depends on more fundamental regulatory reforms, discussed earlier in the paper, and the imposition of some form of carbon pricing to make coal less competitive which goes beyond the accumulation of revenues from a coal tax in a 'clean energy fund'. However, given the drive towards universal electrification in India by 2019, coal is unlikely to be discouraged, implying a rather limited role for gas in power.

These observations on power suggest a downward adjustment of 'wildly optimistic' forecasts for gas demand to more plausible levels. This more conservative forecast for the power sector could nevertheless be further biased in favour of coal, as it is difficult to account for the possibility of a further softening in the international market for coal – from the backing out of coal in Europe, China and the US.

At the time of writing, the government had approved the 'pooling' of domestic gas with imported LNG to obtain a lower average price. This could result in a short-term rise in gas use in the power sector, where a large proportion of gas fired capacity has remained stranded due to the shortage of domestic gas. This is arguably unsustainable in the longer-run, particularly if the low gas price environment does not persist – and could in fact end up compounding India's 'circular' problem with gas price reform, as

: low gas prices are unlikely to incentivise new domestic production, which could potentially lead to higher-priced LNG imports becoming the main source of incremental gas, and

: gas price pooling could provide a further disincentive to reforms, as governments may prefer to retain control over the price of domestic gas in order to moderate the impact of higher-priced incremental LNG imports.

The outlook for the city gas sector is relatively more optimistic, especially after city gas for households (PNG) and transportation (CNG) were moved to the top of Tier 1 consumers in the 'two-tier' structure of gas demand described in this paper. The improved price competitiveness of city gas against diesel and LPG (on the back of recent petroleum product pricing reforms), along with the fact that city gas distribution entities are allowed unregulated pricing (and the passing through of upstream price increases), implies that investments in expanding city gas infrastructure should be forthcoming. However, it is unlikely to match potential demand in fertilisers or replace the lost potential for gas in power in the medium term, and the question remains as to how much gas this sector can realistically absorb in the next few years.

These conclusions, and a potential downward adjustment in demand forecasts indicate a theoretical potential for LNG imports by 2030, amounting to roughly 100 Bcm, implying that India would rival both Japan and China as a driver of global LNG trade within the next 15 years. However, this forecast needs to be qualified, specifically in the power sector, by uncertainties relating to India's push on coal, and the very realistic possibility of a greater reliance on coal imports in a softening international coal market, as mentioned earlier. Contingent upon these dynamics, the 100 Bcm could be an overestimate.

Nevertheless, whether any of this future potential for LNG imports can and will be fulfilled is dependent on two factors: first, whether Indian buyers are able to contract volumes at 'acceptable' (to end-users) prices, and second, whether India can develop the infrastructural capability to receive and distribute these volumes. As shown in this paper, India's current long-term contracts leave a portion of this import potential (30 Bcma based on a relatively conservative forecast) unmet. 'Actual' import potential is likely to be somewhere between the two 'poles' (conservative and optimistic) discussed in this paper, which are difficult to determine with confidence due to the lack of a clear pricing signal. However, it is very likely that India will face a soft LNG market around 2020, particularly if the TAPI pipeline project comes online (and even if it does not).

Looking ahead, perhaps the most important observation from the analysis in this paper is that India continues to lack a clear roadmap for gas pricing reform, and indeed a roadmap for the role of gas in the Indian economy relative to other energy sources. This is reflected in the variety of projections for gas 'demand' reviewed in this paper.

India has no clear long-term goal on the role of gas in its economy. Economies such as China and Russia have had clear time-defined (for instance, 5 years at the minimum) 'transitions' towards a specific goal in gas pricing reform. In the case of Russia, it was to bring low (controlled) domestic prices up to European export (netback) levels in the pursuit of a set of objectives including financing the replacement of Soviet-era fields with new, more expensive production, and complying with WTO requirements. In China – which is more comparable with India - it was to scale up the use of gas in the economy relative to coal in the transition to less-polluting forms of economic growth. In India, although the government has pledged to review the pricing formula every 6 months – which is significant given long periods of inactivity in the past, it is as yet unclear what the long-term or medium-term goal of reform is – for instance, to make gas competitive with coal for environmental reasons, to replace other fuels (such as oil) with gas for fiscal and budgetary reasons, or to retain a proportion of gas as backup generation in the pursuit of renewable energy. This is different from and more nuanced than the approach towards 'energy (supply) security' that has been pursued by the successive governments – in other words, the race to obtain secure and adequate energy supplies to maintain growth rates whilst also continuing to connect poorer sections of the population to the system for modern commercial energy. A 5 year timeframe could for instance be set out keeping in mind likely developments in the market for internationally traded gas over the same period – which could see a period of oversupply around 2020 when new LNG developments are expected to come on stream. Absent a clear goal and a timeframe for achieving this, uncertainty over the price level, and a continued effort to manage this price level, is likely to persist and perpetuate the decline in the upstream sector.

India lacks a price formation mechanism which in some way reflects the dynamics of the Indian market. Linked to the need for a longer-term goal for natural gas in India's economy is the importance of moving from the focus on price level to a price formation mechanism that reflects the evolution of the Indian gas market. For instance, in China's reform process, gas prices have been determined by the fuels they are replacing in the domestic economy – fuel oil, LPG and LNG imports. China's 2011 'netback' gas pricing policy linked the benchmark gas price (Shanghai city gate) to the import price of LPG and fuel oil, which are substitutes for gas. This dynamic price formation mechanism has been further modified to reflect regional market fundamentals as the reforms have

progressed and China's gas market has expanded and developed across its provinces.[153] For India, one could look at the three most relevant gas consuming sectors – fertilisers, city gas and power. This paper has discussed how capacity in the fertiliser sector has nearly all converted to natural gas-based manufacturing –and therefore the feedstock alternative to domestic gas is imported LNG. In city gas, CNG has become price competitive with diesel, and the price competitiveness of PNG with LPG has also improved – LPG and imported LNG are thus the main alternatives to domestic gas in the city gas sector. In the power sector, the obvious alternatives to domestic gas are coal – which severely restricts the potential for gas in power, and imported LNG. It is therefore plausible that linkages to imported LNG (but relevant to India) need to be reflected in a price formation mechanism as representing opportunity cost, along with linkages to alternative fuels in the domestic market, particularly coal.

One option being explored is the establishment of a traded price for a proportion of domestic gas – but this has limited relevance as gas forms a relatively small proportion of India's energy balances. This option would involve stimulating the development of a gas trading 'hub' which could represent a gradually increasing proportion of consumption. However, there are significant challenges to this (as evidenced by the 5-10 year period required in most European countries) – such as (amongst other factors) setting up a trading platform, and ensuring that the traded price is representative of the broader pattern of gas consumption in order to obtain as 'true' a price as possible. Further, in these countries, market liberalisation was a necessary step both in relation to prices and infrastructure (access to pipelines and LNG terminals) in order to involve a sufficiently large number of players in order to produce a contestable market price. Such a market would need to include Tier 1 consumers (who have been averse to higher gas prices for reasons shown in the analysis in this paper), whereas in the past gas (mainly LNG) at market prices has largely found a market with Tier 2 consumers. More importantly success would entirely depend on a demonstrable commitment by the government to supporting its development. India's situation is much more comparable to China than to Russia in this regard – Russia has a gas industry which accounts for 50% of its energy balance, all of which is accounted for by domestic production. In contrast, India's gas sector accounts for a small fraction of its energy balance, with India as a net importer of gas, which has to compete with subsidised fuels such as coal. A comparable option in China would be the move towards a 'Shanghai city gate price' – however, India arguably has a long way to go in terms of the development of requisite infrastructure and stimulation of the use of gas in the wider economy.

The most likely outcome going forward is a continuation of the present system, potentially incorporating some elements of a market-based price formation mechanism. However, implicit price controls need to be recognised in order for any effective progress to be made. For instance, the calculation of a premium to the domestic gas price for deep water and ultra-deep water production may need to recognise the capital constraints of the NOCs (whose capital outlays, as discussed, are influenced by their 'fiscal' function – that is, partially taking on the financing of subsidies). Alternatively, the premium could be linked to elements of a price formation mechanism. The problem with a continuation of the *status quo* however, is that in the absence of a longer-term vision it fails to resolve the uncertainty that has deterred the development of the gas sector.

Comparable with the recent completion of petroleum product price reforms parallel with the low international oil price, gas price reform (in terms of introducing a price formation mechanism relevant to the Indian market) is arguably easier to carry out in a low global gas price environment – the current situation could represent a missed opportunity, implying further difficulty in progressing with reforms in the event that LNG prices begin to rise.

Under present conditions, the reality indicates a much more muted role for gas in India's economic story than the rhetoric would suggest. This is particularly so in the absence of a clear long-term (5

[153] Chen (2014)

year) goal for its use in economic growth, and of a transition to a market-related price formation mechanism which would promote an increase in both domestic production and imports.

Acronyms

APM - Administered Pricing Mechanism
Bcm – Billion cubic metres
CNG – Compressed Natural Gas
JCC - Japan Customs Cleared
kWh – Kilowatt Hour
LSHS - Low Sulphur Heavy Stock
mcm – thousand cubic metres
MMBtu – Million British thermal units
MMscmd – Million standard cubic metres per day
Mtoe – Million tonnes oil equivalent
mtpa – Million tonnes per annum
Mt – Million tonnes
NELP – New Exploration Licensing Policy
NOC - National Oil Company
OIL – Oil India Limited
ONGC - Oil and Natural gas Corporation
PEL- Petroleum Exploration License
PNG – Piped Natural Gas
scm – standard cubic metres
Tcf – Trillion cubic feet
Tcm – Trillion cubic metres
$ - US Dollar
₹ - Indian Rupees

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