The Challenges Facing India on its Road to a Gas-Based Economy

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Key Points

Indian policymakers have stressed the role and relevance of natural gas in India's overall energy mix in the 21st century but expectations of its share have been scaled back. For example, the Hydrocarbon Vision 2025, released in 1999, projected the share of gas would reach 20 percent of the primary energy mix by 2025, while India's current vision puts this target at 15 percent by 2030. Now, however, India's climate change pledge at the United Nations Conference of Parties 21 (COP21) is set to reverse this with policies to promote gas in industry and transportation as well as its complementary role in achieving ambitious renewable energy targets in the long term.

India Hydrocarbon Vision 2025 – projections for gas share (% of primary energy mix) against actual gas share for 2001-2, 2006-7 and 2010-11.

Source: (i) Hydrocarbon Vision 2025; and (ii) Energy Statistics 2018, Ministry of Statistics and Programme Implementation, Government of India.

The study finds that:

Despite previous reform measures, prices for the greater part of India's gas supplies are still government controlled and set arbitrarily rather than determined by market forces. This leads to affordability issues – the number one challenge in Indian energy policy.

Key Points

Indexing Indian upstream gas prices with international markets with different dynamics, may not be as effective as using opportunity costs linked to liquefied natural gas (LNG) import parities or weighted average of fuel oil and coal in bringing prices closer to the market's ability to afford them. But the delivered cost of gas includes taxes that make its use uneconomical in India for power generators and other users.

'Postage stamp' transportation pricing could introduce simplicity, and encourage more homogeneous economic growth and market development in the short term although the resulting long term distortions would have to be addressed in the future.

Power and fertilizer manufacture have remained the country's two anchor gas consuming sectors. Lower domestic gas production than expected and higher international LNG prices have rendered the use of gas uneconomical for power generation. The growth of a gas-based economy would require expansion to industry, transport and households.

Progress has been hampered by jurisdictional conflicts between multiple regulators. This can be streamlined by strengthening the role of the Petroleum and Natural Gas Regulatory Board as a market operator in the midstream/downstream segment and assigning greater upstream regulating power to the Directorate General of Hydrocarbons.

Gas pipelines are currently limited to regions where domestic gas production and LNG import terminals are located. Realizing the vision of a gas-based economy in India will require a clear roadmap and coherent planning approach.

Executive Summary

India could become one of the world's largest gas consumers, as its consumption is driven by a growing population, a thriving economy and the need to reach ambitious climate change targets aimed at reducing its carbon footprint. At the same time, it has a pressing need to deliver electricity and clean cooking fuel to its population and to expand its economy. But the past few years have highlighted the challenges which have continued to prevent it reaching its gas targets. This study was informed by a series of stakeholder interviews and an extensive literature review to identify the key issues faced by the Indian natural gas sector. It sets out the findings as a baseline against which to evaluate future policy options.

Despite India's gas market being almost equivalent to the largest European gas markets in terms of size, the presence of international investors remains limited. Strong government intervention from upstream to downstream has prevented market forces from operating effectively. In addition, the limited introduction of previously announced reforms has left the sector semi-liberalized and semi-controlled.

Pricing and affordability are the key gas issues in India as both the existing consumption sectors, including power and fertilizer, and emerging sectors such as city gas are considered very price-sensitive. Further, linking upstream prices with international markets – which have different dynamics and limited similarity to the Indian market – as part of price reform measures introduced in the past has increased the complexity of and uncertainty in price formation. It has also set a benchmark that is inadequate for developing a competitive market. The cure would involve reforming and rationalizing upstream gas pricing mechanisms. Basing prices on opportunity cost (linked to imported liquefied natural gas (LNG) or

weighted average of fuel oil and coal), introduced recently for new production facilities, might address some of the pricing issues in the gas sector.

Natural gas is taxed differently and has a high tax component compared to coal, despite the latter's higher environmental footprint. This makes the use of gas uneconomical in India for power generation and other users. There is a need for a consistent fiscal policy on levying a tax on natural gas along the value chain. Rationalizing the zonal pricing approach for gas pipelines, which changes every 300 kilometers, through 'postage stamp' transportation pricing could bring simplicity and encourage more homogeneous economic growth and market development.

Three different entities – the Ministry of Petroleum and Natural Gas (MoPNG), the Directorate General of Hydrocarbons (DGH) and the Petroleum and Natural Gas Regulatory Board (PNGRB) – are in charge of natural gas regulation. The weak and ambiguous mandate of the PNGRB, particularly as regards price setting, has led to several jurisdictional conflicts with the MoPNG in the past. Enhancing the regulator's role as an enabler and facilitator would help create markets, as would bringing greater clarity to the role of the DGH, an upstream regulator, and giving it greater powers to regulate the upstream sector. These are important steps to enable the transition to a gas-based economy, as set out in the government's vision.

Boosting domestic gas production will be key to the creation of a gas-based economy. Natural gas includes conventional, as well as deepwater and unconventional, resources. While the government's earlier New Exploration Licensing Policy (NELP) succeeded in opening the upstream sector to private and international players, it failed to increase domestic production or to attract

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substantial foreign investment, due to various problems. These problems included the time-consuming and bureaucratic approval process, the quality and availability of field data, the lack of clarity on policy-related issues including uncertainties in the tax regime, the design of production-sharing contracts, and state intervention in the pricing and allocation of gas. India's new Hydrocarbon Exploration and Licensing Policy (HELP) aims to address some of the challenges previously faced by NELP. However, its successful implementation through the Open Acreage Programme, which it introduced, will require a geospecific national data repository.

The government has previously attempted, by various means, to increase the share of natural gas in the country's energy mix. Despite this, gas use did not increase as had been envisaged. On the supply side, domestic production, rather than increasing, declined, due to issues with the Krishna Godavari Dhirubhai 6 (KG-D6) offshore gas field in the Bay of Bengal. Rising international LNG prices also affected the trade pattern of imported LNG, besides other infrastructure bottlenecks.

Pipeline infrastructure and demand continue to face the traditional 'chicken and egg' problem. The main obstacles to creating gas demand and boosting gas consumption are: domestic production difficulties, issues in the pricing and allocation of gas, imperfect regulatory practices and inadequate infrastructure. Many experts believe that creating adequate gas infrastructure – known as the 'carrier first' strategy – is the key prerequisite for demand creation. However, many pipelines have failed to move forward because of lack of demand or unfavorable economics. Market players increasingly request state support in the form of viability gap funding (VGF) schemes to safeguard their investment risks. However, the

modalities and effectiveness of VGF support schemes need to be reassessed from time to time.

Underutilization of gas pipelines affects not only the risk-return profile for the existing owners, public or private, but may also dampen future investment prospects. Moreover, the government's control over domestic gas allocation and its changing priorities are boosting demand from different sectors at different points in time. This may affect long-term gas infrastructure investment prospects because of the uncertain availability of gas for various end-consumers.

The significant delays in developing the pipeline infrastructure associated with the Kochi LNG Terminal highlight the need for greater coordination among the players in the upstream and midstream sectors. More importantly, the potential 'right of way' issues need to be assessed and addressed in the planning phase to avoid or minimize unforeseen circumstances that could hamper the project.

In developing a gas-based economy, the government is exploring markets other than the price-sensitive fertilizer and power users, alongside other measures. However, increasing the share of natural gas in the energy mix from around 6 percent in 2017 to 15 percent by 2030 will be challenging. It will require a better appreciation of the problems across the gas value chain and may require 'outside the box' thinking to address them.

Creating a gas-based economy implies that in each consuming sector the share of gas should grow. This is particularly controversial in India's power sector, where gas is being squeezed between renewables and coal because gas-fired plants are more expensive than the alternatives. As various state governments resist raising electricity rates for

politically sensitive groups of consumers, such as the domestic and agriculture segments, the high cost of electricity production will only increase the sector's dependence on government subsidies. Accordingly, a key question is whether gas should

be confined to a balancing role or find a larger share in the power mix when its environmental benefits are appropriately recognized. Industry, transport and households are all potential markets for gas in India, but each faces its own set of challenges.

Introduction

Relevance of a gas-based economy

Global natural gas demand has been rising in most parts of the world over the past 15 years, increasing by 42 percent or slightly over 1 trillion cubic meters (tcm). In comparison, Figure 1 shows that gas consumption in India peaked in 2010-11 at 58.93 billion cubic meters (bcm); since then it has shown a steady decline. Major factors behind the decline in India's consumption include falling domestic production, which peaked in 2010-11, multiple pricing mechanisms, and regulatory framework and infrastructure issues, among others. In terms of gas consumption by sector, power and fertilizer remain the two major gas consumers followed by city gas distribution. Moreover, the share of natural gas in India's energy mix decreased from 10.5 percent in 2010-11 to around 6.7 percent in 2017-18, compared with a global average of approximately 23.4 percent.

Against that background, the government of India has indicated since late 2016 that it plans to increase natural gas penetration and move towards a gas-based economy (PIB 2016a). A campaign was announced under #Gas4India which plans to increase the share of natural gas in India's primary energy mix from the current 6.7 percent to 15 percent – an increase from around 50 bcm currently to more than 200 bcm by 2030 (PIB 2016b). Because natural gas is a much cleaner fuel than coal, increased gas utilization is also expected to help India meet its intended nationally determined contributions (INDC) commitments under the UN Framework Convention on Climate Change by reducing carbon emission intensity by up to between 33 and 35 percent from 2005 levels by 2030. Further, the increased contribution of gas in India's energy supply was expected to:

Reduce India's dependence on crude oil imports, which were around 4.6 million barrels a day (bbl/d), or \$73.4 billion in 2016-17, by substituting the use of oil products in industrial and residential applications. For the transportation sector, domestic gas production would be boosted by "creating gas verticals in different aspects of the economy" (PIB 2016b).

Improve access to electricity and clean cooking for the country's growing population; it will be the most populated country after 2024 (UNDESA 2017). Despite being the third highest primary energy consumer in the world, India's per capita energy consumption is one of the lowest, at 0.530 tonnes of oil equivalent (TOE) (MOSPI 2018). A total of 244 million people do not have access to electricity and 819 million do not have access to clean cooking (IEA 2017).

Historical vision documents

Over the last 15 years, a number of vision documents have been released with differing projections for gas demand for different years (Table 1). Hydrocarbon Vision 2025, published in 1999, called for gas to reach a 20 percent share in primary energy demand by 2025, or 143 bcm by 2024-25. India Vision 2020 (PC 2002) estimated gas demand at 70 bcm in a business as usual scenario (BAU) and around 64 bcm in a best case scenario, which saw the share of natural gas at approximately 9-10 percent. The Integrated Energy Policy 2006 (PC 2006), with its 11 scenarios, projected gas demand at between 94-177 bcm in 2031-32, with the share of natural gas in the primary energy mix ranging between 5.5 percent and 11 percent.

The draft National Energy Plan (NITI Aayog 2017a) forecasts an increase in gas demand from

Figure 1. Availability and consumption of natural gas.

*CGD = city gas distribution.

Source: (i) Petroleum Planning & Analysis Cell, MoPNG, 2018; (ii) Petronet LNG, June 2018 and (iii) Energy Statistics 2018, Central Statistics Office, Ministry of Statistics and Programme Implementation, Government of India.

Table 1. Different projections of gas demand.

Visions	Year of projection	Gas demand (bcm)	Share in primary energy mix (percent)
Hydrocarbon Vision 2025	2024-25	143	20
India Vision 2020	2020	64-70	9-10
IEP** 2006	2031-32	94-177	5.5-11
Draft National Energy Plan	2040	95-124	9

**IEP = Integrated Energy Policy.

Source: Vision and policy documents, Government of India.

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6.5 percent currently to 8-9 percent in 2040, an increase from around 50 bcm in 2015-16 to 95 bcm in the BAU scenario, and 124 bcm in the ambitious scenario. However, none of the projections aimed at boosting the share of gas in the energy mix set out in any of the visions have, in fact, materialized during the intervening years. For example, in Hydrocarbon Vision 2025, considering the expected evolution of the respective fuels between 2000 and 2025, gas was expected to be the big winner against coal and oil, the shares of which were expected to drop over time. However, on comparing the targets with the actual energy picture (Figure 2), gas has clearly missed its target

of reaching 14 percent (2010-11) of the primary energy mix, given that its share in the mix was only 6.2 percent in 2017-18.

Moreover, a review of the documents mentioned in Table 1 suggests there has been a gap between the projected and actual demand in the past (Table 2). This is evident as far back as the 1999-2000 numbers – 40 bcm of expected demand against 28 bcm actually consumed. Over the following years, the gap between expectations and actual consumption was never bridged but, in fact, widened. India's gas consumption peaked in 2011 and dropped to around 50 bcm thereafter.

Figure 2. India Hydrocarbon Vision 2025 – projections for gas share (% of primary energy mix) against actual gas share for 2001-2, 2006-7 and 2010-11.

Source: (i) Hydrocarbon Vision 2025; and (ii) Energy Statistics 2018, Ministry of Statistics and Programme Implementation, Government of India.

Table 2. Projected demand versus actual consumption of natural gas (in bcm).

Years	Hydrocarbon Vision 2025	IEP 2006*	Draft NEP**	India Vision 2020***	Actual demand
1999-00	40				28
2001-02	55				28
2006-07	84				38
2011-12	114	40			62
2015-16					48
2016-17		58			50
2019-20				64	
2021-22		87	53		
2024-25	143				
2026-27		122			
2031-32		177			

*One of the scenarios from the IEP 2006, which looks at the share of gas-based power generation at 16%.

**The ambitious scenario in the draft National Energy Plan (NEP).

***The best case scenario in the India Vision 2020 document.

Source: KAPSARC.

This brings us to the question of where did the projections go wrong? Hydrocarbon Vision 2025, the first of the ‘visions’, considered a mix of domestic gas and imported LNG to ensure the adequate availability of gas. On the other hand, the Integrated Energy Policy (IEP) of 2006 (PC 2006) and India Vision 2020 (PC 2002) assumed a limited availability of domestic gas until further exploration and production was successful, and expressed a reliance on importing gas through pipelines and LNG, on bilateral contracts, to meet demand.

On the supply side, all elements underperformed. Domestic production increased between 2009-11 but then fell back due to the issues with the Krishna Godavari Dhirubhai 6 (KG-D6) field. At 32 bcm, as of 2017, domestic output has almost fallen to the levels of the mid-2000s. The proposed tapping of unconventional sources of natural gas

like coalbed methane (CBM), natural gas hydrates, and underground coal gasification was clearly not achieved. CBM production is marginal, despite efforts to develop it. As of 2017, India imported over 19 million tonnes per annum (mtpa) (26 bcm) of LNG – a record, even if it hides an underutilization of LNG import terminals since two out of four are not fully operational. However, even if the terminals were all fully utilized, importing more than 25 mtpa, that would not be enough to reach the consumption targets of over 110 bcm as projected in Hydrocarbon Vision 2025. The targets for 2016-17 established in the IEP and India Vision 2020 could, however, be met (Table 2). In addition, no import pipeline has been built outside India as a result of sanctions against Iran and no progress has been made with India’s eastern neighbors. The Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline has seen many delays due to the complexity of the project,

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but work is reported to have begun on the Afghan section in late February 2018. Myanmar's resources, however, have been going to China instead.

IEP 2006 also stated that, if domestic production was inadequate, domestic natural gas should be allocated and its pricing regulated independently, on a cost-plus basis, at least until supply caught up with demand. However, the multiple pricing regimes that followed further dampened the prospects of creating demand for gas, due to uncertain economics. Lack of demand also hit infrastructure development and led to underutilization of existing capacity in pipelines and gas-based power plants. As a result, nearly 14.3 GW of gas-fired generation capacity was sitting idle (Lok Sabha 2017). If this were run as baseload at 90 percent, the plants would use as much as 22 bcm per year of gas. But to do that, supply and pipelines would have to be available and prices low enough for gas to be used.

Achieving a gas-based economy

There is no Indian government primary energy demand forecast as such. Nevertheless, NITI Aayog

has developed energy forecasts as part of the Draft National Energy Policy (NITI Aayog 2017b). This highlights four key priorities for energy policy: access to gas at affordable prices, improved security and independence, greater sustainability and economic growth. The first directly relates to the reduction of poverty, including energy poverty, and increasing access to electricity and clean cooking. India also imports oil, gas and coal – energy security could be enhanced both through diversification of import sources and by increased domestic production and lower total energy demand. The third priority is linked to the need to reduce carbon emissions. Fourthly, energy must promote economic growth, either directly or by fostering investment.

In the NITI Aayog forecasts, gas demand is expected to triple from the current level to 152-154 million tonnes of oil equivalent (MTOE) by 2040 (Table 3). This is equivalent to 168-171 bcm in the BAU and High Gas scenarios. Also, the share of gas in the energy mix does not increase to more than between 8 and 9 percent by 2040, far from the targeted 15 percent.

The gas economy plans previously highlighted by Shri Dharmendra Pradhan, Minister for Oil and

Table 3. Projected primary energy supply (MTOE).

	2012	2022 (BAU)	2022 (ambitious)	2040 (BAU)	2040 (ambitious)
Renewable and clean energy	23	69	71	173	224
Coal	282	518	475	973	725
Oil	166	260	237	519	420
Gas	49	88	87	152	154
Others	91	95	99	116	140
Total	612	1029	970	1933	1662

Source: NITI Aayog 2017b.

Note: Draft policy presents the projects in equivalent TWh. A conversion factor of 1 MTOE = 11.63 TWh and 1 MTOE = 1.11 bcm has been used to express the projections in equivalent MTOE and bcm units as in the NITI Aayog report Energizing India.

Natural Gas, provide some insights as to what the government wants to achieve (MoPNG 2016):

- Development of gas sources, either through domestic gas exploration and production activities or by building up LNG import facilities.
- Development of gas pipeline infrastructure and the secondary distribution network.
- Development of gas-consuming markets like fertilizer, power, transport and industry.

While these targets make good sense at first sight, the devil is in the detail.

On the supply side, the focus is on existing sources of supply: domestic gas and LNG. Pipelines from other countries are no longer mentioned, unlike in the government's previous vision. The new Hydrocarbon Exploration and Licensing Policy (HELP) is now aiming to boost domestic gas production through several initiatives such as expediting development of existing discoveries, developing marginal or small fields, and establishing marketing freedom for gas produced from deepwater and ultra-deepwater areas, and from small fields (MoPNG 2016). There is still a focus on the D6 field in the Krishna Godavari (KG) basin, despite its disappointing performance so far. Meanwhile, the increase in LNG imports is to be supported by an increase in India's LNG import capacity from 21 mtpa to 55 mtpa (Gas4India 2016). However, capacity does not automatically mean supply: import capacity must be operational – connected to downstream pipelines, for example – and the Indian market attractive enough to draw in the LNG. The planned reduction of LNG import duty, however, moves in that direction. But to fulfill government targets, even 55 mtpa of imported LNG used at 90 percent would meet around a quarter of the projected gas demand. This implies a steep rise

in domestic production, or a further expansion of LNG import capacity – plus some added clarity as to actual LNG supply.

On the infrastructure side, the government will allocate funds from its budget to boost the country's gas pipeline infrastructure (Gas4India 2016). The Gas Authority of India Limited (GAIL), a natural gas transmission company, plans to build another 15,000 kilometers (km) of gas pipelines to increase gas distribution, though historically India's pipeline expansion plans have fallen short of expectations.

On the demand side, the focus is still on the power and fertilizer sectors, which together represent 60 percent of the current total gas demand. However, government plans offer no solution to one fundamental problem: these two sectors are extremely price sensitive and are said to be unable to afford gas if prices rise above \$5.00 per million British thermal units (MMBtu) (The Hindu BusinessLine 2016). Both sectors present significant challenges in terms of growing gas demand, particularly the power sector. The government has proposed a gas pooling scheme for the fertilizer sector, to encourage the utilization of installed fertilizer units in the country. In an initial press release, the Minister of Petroleum and Natural Gas also mentioned a program to increase LNG use for power plants, but this program, which had resulted in an increase in LNG imports in 2016, was discontinued in 2017. In addition, the sharp increase in solar capacity calls for more flexibility, though the actual increase in gas demand resulting from this may be limited as plants are used for mid-merit or peak purposes. The minister said there would be new anchor customers, like the new smart cities, for example, using gas for cooking and transport; but here, too, past developments have been disappointing. While a focus on all sectors would be necessary to reach the proposed

demand levels, the government has not cited a possible range for its objectives or proposed how they would be reached in practice. This will require innovative solutions, the political will to make the strategy happen and practical implementation plans.

This study aims to understand the future of gas in India by analyzing the various complexities that govern the supply of the fuel in the country, and seeking to understand what possibilities there may be to increase its penetration in some of its anchor

consumer sectors. Accordingly, it aims to present issues currently faced by India in the gas, and to a lesser extent the power, markets. The analysis reflects an extensive literature review which was followed by interviews with various stakeholders. The views that contributed to this study were given on an anonymous basis. Instead of beginning with the gas value chain, the study looks at themes which in our opinion reflect the main issues faced by gas in India: market design, policy, regulation and pricing. The analysis of each of the themes then considers the different parts of the gas value chain.

Market Design – Current Perspective and Future Challenges

Given the way in which India's gas market has functioned in the past, and the pitfalls that come with centralized planning and resource allocation, the natural gas market in India has two main features: the government's major say in the market – in the form of target setting and price setting – plus the presence of a large concentration of national oil companies (NOCs). This market structure has had an impact on competition, on prices as well as on final demand. There is nothing wrong with a strong role for the government in the first stage if market forces are then allowed to operate effectively and to be expanded. But changes initiated over two decades ago were never fully implemented, leaving the gas sector semi-liberalized and semi-controlled. Further evolution cannot take place as there is no enabling framework. The key characteristics of the Indian gas market, the issues and challenges are briefly presented below.

Government-driven energy markets

At the national level, energy market reform strategies were often proposed by the Planning Commission, which in its new incarnation is now called NITI (National Institute for Transforming India) Aayog. Most energy market reforms were aimed at addressing three core issues: energy availability, energy access and energy affordability. This is also evident from the varying level of energy subsidies and competition prevalent in different energy sub-sectors, including gas. The problem lies in implementing the proposed strategies. The government has been unable to create demand for natural gas despite various past strategies, and that makes any form of target setting redundant.

Further, the presence of a number of separate ministries dealing with different energy resources, unclear policy objectives and poor coordination among them makes the government's task of steering the energy markets and achieving any kind of national vision challenging (KPMG 2016). This results in significant challenges for coal-gas competition, interfuel pricing and taxation. For example, there are two energy ministers: one for petroleum and natural gas and the other for power, coal, new and renewable energy and mines. Though, on the one hand, the Minister for Petroleum and Natural Gas has stated that he expects the share of natural gas in the energy mix to increase to 15 percent, one of the main anchor consumers, the power sector (for which another ministerial colleague is responsible) appears to be moving away from gas-based power generation. Indeed, the draft National Electricity Plan (CEA 2016) seeks to use gas-based power generation for only six hours a day for peaking purposes.

This creates a disconnect in policymaking and an incoherence in implementation, which results in confusion among investors and gas players along the supply chain. This kind of split in the decision-making body is not seen in other major energy players around the world. In the United States (U.S.), for example, the Department of Energy is responsible for energy, environmental and nuclear issues. In China, the National Energy Commission coordinates overall Chinese energy policies. In Japan, energy policy is in the hands of the Ministry of Economics, Trade and Industry. There are other countries with different ministries in charge of various parts of the energy industry, but they must be strongly coordinated to avoid giving mixed messages to investors.

Role of PSUs and private players

As in many markets, the Indian gas sector started with state-owned companies, known as public sector undertakings (PSUs), like the Oil and Natural Gas Corporation (ONGC), Oil India and GAIL. Despite various attempts by the ministry to introduce competition in the oil and gas markets through policies such as NELP, there has been little headway because of the way Indian policy is designed. Consequently, the PSUs still have a very strong role in different parts of the gas value chain. Some of these government companies appear to want a more integrated position in the market. For example, the business development and joint ventures group of ONGC looks at opportunities for “driving value integration in hydrocarbon molecule beyond the E&P [exploration and production] domain,” and several projects have been initiated in the field of petrochemicals, power, wind, fertilizers and the Special Economic Zone (ONGC 2017). Similarly, the Indian Oil Corporation Limited (IOCL) is already in the regasification business through Petronet but is trying to enter directly by taking a stake in LNG terminals. It already has investments in upstream as well as in city gas distribution (CGD) (Emerald 2017). Shell is so far the only foreign player to pursue that strategy, with investments in LNG infrastructure and supply and in city gas. It also plans to expand its downstream gas marketing activities to supply gas to power plants, fertilizer producers, petrochemical producers and city gas developers (Pathak 2017).

As in some countries – for example, in pre-liberalization Europe – India has a couple of government-owned integrated gas companies strongly present throughout the gas value chain. While ONGC and Oil India have been more

dedicated to production, GAIL has exploration and production activities and has been active on the LNG side and in city gas development, even though it was initially more focused on pipeline infrastructure. Another integrated company is the Gujarat State Petroleum Corporation (GSPC), the only oil and gas conglomerate to be promoted by a state government in India.

Despite India’s gas market being comparatively large – almost as big as the largest European gas markets – the presence of international investors is not very strong. Some players such as the United Kingdom’s (U.K.) multinational BP, Anglo-Dutch Shell, Australia’s Cairn, and Eni of Italy operate in the upstream sector, though a few others have left. Shell and Total of France are present in the LNG business, while French multinational Engie exited Petronet LNG in June 2017. No foreign player has so far invested in the gas pipeline business. On the downstream side, Shell (formerly BG) is present through the compressed natural gas (CNG) retailer Mahanagar Gas Limited in Mumbai.

Upstream – lack of private sector participation

In the 1990s, India’s upstream sector was opened up to private and foreign players. Nine bidding rounds were organized under NELP (Figure 3). The main thrust of NELP was to provide a level playing field for both the public and private sector companies in hydrocarbon E&P. Still, despite interest from foreign players, PSUs (ONGC and Oil India) won a large proportion of acreage under these bidding rounds, which was then added to their existing dominant upstream position (Table 4).

The concentration of NOCs is not a problem, as such. There are, for example, many NOCs in China, Russia, and in many Middle Eastern

Figure 3. Performance of various NELP bidding rounds.

Source: Directorate General of Hydrocarbons.

Table 4. Participation by public and private companies in the NELP rounds.

Round	Public sector company/joint venture (JV)	Private company/private JV	Total blocks awarded
NELP-I	10	14	24
NELP-II	18	5	23
NELP-III	14	9	23
NELP-IV	18	2	20
NELP-V	12	8	20
NELP-VI	35	17	52
NELP-VII	24	17	41
NELP-VIII	18	14	32
NELP-IX	10	9	19
Total blocks	159	95	254

Source: Directorate General of Hydrocarbons.

countries, and production has been growing in all these geographies. However, the exploration efforts of PSUs in India have underperformed, adding reserves of just 81 MTOE as against the aggregate target of around 276 MTOE (CAG 2013). Companies acquiring acreage offshore India need to fulfill their exploration commitments (Sen 2016). Annex II describes the exploration efforts of ONGC in various rounds of NELP, along with further details of private players in E&P activities. The subsequent section on policy discusses key factors that contributed to less than expected participation from private players.

Midstream – a mix of PSUs and private companies

The midstream sector offers a slightly different picture, particularly on the LNG side. The policy of favorable terms adopted at the outset encouraged a mix of foreign and domestic players. PSUs are also present in the areas of LNG infrastructure and contracting. ONGC, GAIL, IOCL and Bharat Petroleum Corporation are the main promoters of Petronet LNG. France's Engie and Asian Development Bank sold their stakes of 5.2 percent and 10 percent respectively to Petronet LNG in 2014 and 2017. Petronet LNG currently operates two LNG terminals, Dahej and Kochi, which together account for two-thirds of the existing operational LNG terminal capacity of 30 million metric tonnes per annum (mmtpa). GAIL also owns Dabhol, the third LNG terminal, while Total and Shell jointly own the fourth merchant terminal, Hazira.

Despite clearances given for 15 terminals in 2000, only four have materialized over the last 16 years (Table 5). A considerable delay by Petronet LNG (PLL) and, on occasion, projects – such as the ones at Mangalore and Ennore – not being taken

up, were factors behind the slow infrastructure development. Moreover, towards the end of 1999, the Ministry of Petroleum and Natural Gas (MoPNG) directed the management of Petronet LNG not to take up any project or activity that would have an adverse effect on the Dahej and Kochi terminals (CAG 2014). This contradicted the Hydrocarbon Vision 2025 which envisaged domestic companies both setting up terminals and taking part in the LNG supply chain.

There is still a mix of PSUs and private companies involved in India's LNG terminals (Table 5). Other private players have also considered entering the LNG scene through new LNG terminal projects. As these terminals are mostly at the preliminary stages (planned/proposed), it is difficult to be certain whether they will actually go ahead or not. Reasons for this uncertainty include the complexity of the LNG supply chain. A terminal cannot be brought into operation if there is no existing pipeline infrastructure or connectivity for gas offtake beyond the port. Further, LNG terminals need substantial investment, and there is little certainty of that without an existing market.

The most advanced projects are Mundra LNG and Ennore, currently under construction. Mundra LNG is supported by Adani and the GSPC, though the latter has bid to exit the project by selling its stake to Indian Oil, the major Ennore stakeholder. Shell and Engie abandoned a floating storage and regasification unit (FSRU) project at Kakinada in Andhra Pradesh in early 2017, most probably because of the lack of both LNG demand and gas infrastructure in India. There are other FSRUs planned, but none have been confirmed as yet. The absence of a monitoring mechanism to review the progress of the terminals sanctioned from 1997 to 2000, and other issues, have certainly affected the planned growth of LNG.

Table 5. Status of LNG terminals (July 2018).

#	Terminal	Capacity (mmtpa)	Online	Developer
1	Dahej	15 (5+5+5)	2004/2009/2016	Petronet LNG
2	Hazira	5	2005	Shell, Total
3	Dabhol	5	2013	GAIL, NTPC
4	Kochi	5	2013	Petronet LNG
	Total existing	30		
1A	Dahej Expansion Phase III B	2.5	2018*	Petronet LNG
5	Mundra	5	2018*	GSPC, Adani
6	Ennore	5	2018*	IOC, TIDCO
	Total under construction	12.5		
7	Kakinada	2.5		APGDC
8	Dhamra	5		Adani
9	Jafrabad (FSRU)	5		Swan, Exmar
10	Jaigarh	2.5		H-Energy
	Total planned	15		
11	Gangavaram	5		Petronet LNG
12	Kolkata Port	2.5		H-Energy
13	Chhara	5		HPCL & Shapoorji Pallonji
14	Krishnapatnam	2.5		LNG Bharat
	Total proposed	15		
	Grand total	72.5		

Source: Petronet LNG Limited, 2018.

*Current forecast

On the gas transmission side, historically pipeline development was under the aegis of producers such as ONGC, OIL, Assam Gas Company Limited and end-consumers. After 1985, GAIL undertook the development of the Hazira-Vijaipur-Jagdishpur pipeline and the regional networks, while GSPC undertook pipeline development in Gujarat. However, GAIL was responsible for developing the national gas grid and in 2000 received approval to undertake work on seven trunk pipelines: Hazira-Uran-Mangalore/Bangalore, Kochi-Kasargod-

Mangalore, Mangalore-Hassan-Bangalore, Bangalore-Chennai, Uran-Hyderabad-Kakinada, West Bengal-Bihar-UP and West Bengal-Orissa-AP-TN. In the meantime, Reliance Industries Limited (RIL), which had discovered the KG-D6 field, moved into gas pipelines through Reliance Gas Transportation Infrastructure Ltd (RGITL). In 2007, GAIL and RIL signed a gas transmission agreement to share each other's pipelines for the transmission of gas supplies from the KG basin fields. The agreement provided for the transportation of gas

from the KG basin, off the east coast of India, through GAIL's network, and for booking capacity by GAIL in RGTIL's East-West Gas Pipeline (Corbeau 2011). However, this has not progressed as anticipated.

As of the end of the financial year (FY) 2017-18, GAIL is India's largest gas transmission company by far, with around 11,000 km of pipelines, representing three-quarters of India's total pipeline capacity (GAIL 2018). Gujarat State Petronet Limited (GSPL) comes second, with around 2,370 km, ahead of RGTIL with 1,460 km. In this sector, there are also a few regional players such as Assam Gas Company, PSUs such as ONGC and a couple of end-users. GSPL has close to 4,800 km of pipelines under construction, followed by GAIL with more than 2,100 km and Oil India with almost 1,400 km. Appendix 1 details the existing and planned gas pipeline network. Failure to develop city gas projects along the pipeline routes and the non-availability of gas considerably delayed the construction of four pipeline projects to be developed by RGTIL: Kakinada-Howrah, Chennai-Tuticorin, Chennai-Bangalore-Mangalore and Kakinada-Chennai. Likewise, GAIL's five pipeline projects (Dadri-Bawana-Nangal, Chainsa-Gurgaon-Jhajjar-Hissar, Jagdishpur-Haldia, Dabhol-Bangalore and Kochi-Kanjirkod-Bangalore-Mangalore) suffered a delay of between three and 24 months due to lack of clarity over gas sourcing, since Relogistics Infrastructure Limited, a subsidiary of RGTIL had not implemented the Kakinada-Howrah/Haldia pipeline. GAIL was also uncertain whether the pipeline would be utilized to its full capacity since five fertilizer plants, which were to be the anchor consumers, had not been upgraded. The point to be taken from this is that pipeline infrastructure should not be delayed by linking it to demand-supply availability as gas can be sourced from international markets (LSS 2012).

After the establishment of the the Petroleum and Natural Gas Regulatory Board (PNGRB), conflicting views between the regulator and the ministry discouraged competitive forces from taking part in the system. This allowed GAIL to retain its dominance and engage in rent-seeking practices (PNGRB 2011, 2014). An unbundling proposal for hiving off GAIL's transport and marketing activities is under discussion. If implemented, this could be an important step by the Indian authorities towards the creation of a gas trading hub.

Liberalization and deregulation

India started to deregulate parts of the gas market, giving market forces free rein, as early as 1991; part of a wider liberalization process taking place in various sectors of the country's economy. In particular, ONGC was reorganized as a public company. The government divested shares through competitive bidding and sold some to the other PSUs. In 1997 it opened up the upstream sector to private and foreign investment through NELP (Corbeau 2011). In the LNG sector, one merchant LNG terminal at Hazira started up in 2005. The initial plan also included reforming gas prices (Corbeau 2011), which after 1997 were linked to an international basket of fuel oil prices.

With these attempts, it might have appeared that the Indian gas sector, initially state-owned, was indeed moving toward liberalization and deregulation. But the gas price proved to be one of the key stumbling blocks. Prices started to rise through the late 1990s but reached the ceiling fixed by the government as soon as October 1999. While international oil and gas prices continued to increase after that, the planned reform was abandoned and the gas price remained fixed at that level. It has been suggested

(Jackson 2005) that this stagnation was a result of electricity and fertilizer producers using their political power to prevent further price increases.

Consequently, a rift appeared in the gas sector between the state-controlled system and the deregulated system, which would in future still need to coexist. The sector remains dominated by this duality. Part of the gas business remained state-controlled through the gas value chain: the allocation policy would require PSUs to sell part of their gas production at controlled (Administered Pricing Mechanism, or APM) prices to consumers deemed ‘price sensitive,’ largely fertilizer producers and power generators. The other part of the gas market was deregulated and would see companies selling gas, both LNG imports and some domestic production, at market prices. Companies such as ONGC that were selling gas at controlled prices were pushing for liberalization, expecting higher prices to result (Jackson 2005). How to transition the price-sensitive gas users from the state-managed sector to the free market sector has remained the main issue for the Indian gas market since then, as international gas prices have increased while in India gas has to compete in the power sector against increasingly competitive coal-fired plants and renewable energy sources.

Further, the government’s Gas Utilization Policy, born out of the insufficient supply of domestic gas, has ended up creating distortions of its own over time (Mathur et al. 2016). Artificial boundaries between domestic gas and LNG have served as a deterrent to natural gas uptake, leading to stranded assets and no expansion in the non-priority sectors. Even in the priority sectors, the decline in domestic gas production and higher LNG prices have resulted in stranded assets, just as was seen in the power sector. The government has been considering a revision of its gas utilization policy in light of changing

priorities, which include a greater power supply and improved availability of piped natural gas. It has mandated a pooling of prices for LNG and domestic gas for use in the fertilizer sector (May 2015), and it is trying to revive gas-based power generation by providing a subsidy through the process of reverse bidding for FY 2016 and FY 2017. However, while price pooling for the fertilizer sector has worked, in the power sector the subsidy provided was insufficient (as discussed in the pricing section).

Central and state government: different views and priorities

There have been several instances of conflicts between the state governments and the central government on gas sector matters in the past. These differing views and priorities resulted in various court battles, of which the state’s dispute with Gujarat has been the most notable. After the discovery of Bombay High gas, off the coast of Mumbai, Gujarat took the lead in developing the state’s natural gas industry. The government of Gujarat acquired small gas fields from ONGC, which had little interest in exploration activities. It set up a company to produce and market the gas and made a large discovery. When at first Gujarat decided to construct its gas pipelines, the central government was not very interested in natural gas. Indeed, after Reliance discovered the KG-D6 offshore fields, the government was concerned about having too much gas. When pipelines to the west were begun, on one side there were pipelines authorized by the central government and on the other those authorized by the state government of Gujarat. The dispute between the Indian government and Gujarat over the pipelines went as far as the Supreme Court. It was eventually decided that natural gas is a central responsibility and that the state government should have no legislative power over the transmission, supply and distribution of gas in Gujarat.

Policy Evolution and Unresolved Issues

Despite India being a federal democracy, policymaking has always been centrally planned. Policy formulation in the energy sector is divided among various ministries responsible for specific energy resources. In particular, the gas industry has suffered not just from central planning but also from ad hoc policy changes that have hindered investment, discouraged competition and hampered overall development. The key policies and implementation challenges across the value chain in the gas industry are highlighted below.

Exploration and production

New Exploration and Licensing Policy (NELP)

The pre-NELP policy regime could not succeed in attracting private sector participation in E&P activities because of a policy design that largely favored the PSUs. Reservation of the most prospective acreage for the NOCs, unattractive fiscal terms, lack of significant finds and delays in signing contracts all hampered private investment. NELP was introduced in 1999 to provide a level playing field for all E&P sector players, besides addressing other concerns. Despite this, the NOCs remained dominant (Table 4). While NELP did succeed in opening up the upstream sector to private and international players, it failed to increase gas production or attract substantial foreign investment. Some of the factors that led to the subdued private sector response include:

The prolonged process from the time of bid submission to the license award. NELP I, for example, took 15 months and NELP VI took about 12 months.

Bureaucratic hurdles in obtaining the multiple approvals necessary to start exploration, including unanticipated challenges in getting environmental clearances after the block was awarded. This meant a company could be awarded a block from which it could neither explore nor produce if it was then deemed to be in a wildlife sanctuary or national park no-go zone.

Bidding clauses related to profit on petroleum or gas, under which the government would take its share of the profit in kind, a condition that served to deter companies from committing gas quantities on a long-term basis, while also negating the 'free' gas market.

The vexed issue of profit-sharing between the central and state governments (before the 12th finance commission), when the state governments also demanded a share of the central government's profit from oil or gas. It was believed that the delay in issuing exploration and production licenses by the state governments resulted from this conflict (TERI 2007).

Production-sharing contracts that do not reflect the different levels of risk involved in various types of blocks, such as onshore, shallow or deep-water. One single production sharing contract (PSC) model cannot cover all risks. Also prices, once determined, remain fixed for a specified term, leaving little flexibility to adjust regulated gas prices to take account of new technology requirements or unforeseen adverse geological conditions.

Risk of state intervention in marketing terms, either in pricing and/or allocation. This was illustrated by the disagreement of the Ambani brothers – the then owners of the Reliance Industries group – with the pricing and allocation of gas from KG-D6, where the Supreme Court of India finally decided that the state had the right to decide on both pricing and allocation.

Hydrocarbon Exploration and Licensing Policy (HELP) and Open Acreage Licensing Policy (OALP)

The HELP regime, adopted in 2016, made a number of changes to NELP. It marks the biggest transition from an era of government control to one of government support for upstream E&P in India (Ladislav 2017) and has the clear target of encouraging exploration and thus increasing oil and gas production. It also amends some of the most important negatively perceived features of NELP. However, whether HELP will be able to change the course of the upstream sector is uncertain at this stage, given the current oil price environment. Nevertheless, it is a step in the right direction. Key policy features are as follows:

- A single, or uniform, license for the exploration and production of all conventional and unconventional hydrocarbons from an entire contract area.

- The freedom to select exploration blocks and bid for any acreage without waiting for a formal government bidding round under the Open Acreage Licensing Policy (OALP), part of HELP. OALP was aimed at enabling faster survey and assessment of areas with oil and gas potential. However, its successful implementation will require a national data repository of geoscientific data.

- The PSC has been replaced with a revenue sharing contract (RSC). There are several examples of countries following both PSC and RSC regimes. While both have their advantages and drawbacks (Mathur et al. 2016), what is needed is for India's hydrocarbon policy to remain stable and consistent for long periods to promote the sector's growth.

- Lower royalty rates than NELP for offshore areas, including a graded system of royalties in which the rates reduce from shallow to ultra-deep exploration areas. Different royalties recognize the greater risk involved in exploring deep-water and ultra-deep areas compared with shallow and onshore areas. However, royalties for onshore areas have been kept the same so that state government revenues remain unaffected.

- Companies to have commercial freedom in pricing and marketing of gas from these blocks. However, the government will use the price calculated in its domestic natural gas pricing guidelines to calculate revenues. If the price discovered on an arm's length basis is higher than that calculation, the government's take will be based on the actual price realized.

Coal Bed Methane (CBM) Policy

India is the third largest producer of coal in the world and has an estimated potential of around 28 bcm (around 92 trillion cubic feet) of CBM, an unconventional source of natural gas trapped in the coal seams. Although the CBM policy was initially introduced in 1997, the first CBM block was awarded in 2001 (Singh 2015). One of the key features of India's CBM policy was the freedom to sell gas to the domestic market. Recent amendments now extend pricing freedom to CBM contractors in a bid to incentivize the CBM sector, boosting gas

Policy Evolution and Unresolved Issues

production. Despite such initiatives, gas production has been limited, totaling 1.64 million standard cubic meters a day (MMscm/d) from four CBM blocks in October 2016. Technical challenges to developing CBM in complex and heterogeneous geological structures and lack of adequate infrastructure facilities continue to pose problems.

LNG import infrastructure

While various government visions speak of the need for LNG imports via terminals because of the steady decline in domestic gas output, there is no specific LNG import infrastructure policy. GAIL, IOCL and ONGC undertook the initial work of LNG infrastructure construction, a joint venture (Petronet LNG or PLL), at the behest of MoPNG in 1995. Multinational companies could set up LNG terminals with 100 percent foreign direct investment

(FDI) and the pricing of LNG was unregulated. Thus, between 1997 and 2000, 13 private entities gained clearance from the Foreign Investment Promotion Board for 15 LNG terminals across India (CAG 2014) under the Open General License. Between 2001-12 no awards were made. The first of the two LNG terminals – Dahej and Hazira – came into operation in 2004-05. The Dabhol and Kochi terminals started up in 2013-14, about 14 years after being licensed. Unfortunately, these two terminals remain underutilized (Dabhol 57.07 percent and Kochi 5.46 percent in 2016-17) due to demand-side policy issues and infrastructure issues such as the lack of an all-weather breakwater in Dabhol, and pipeline capacity from Mangalore to other parts of India in the case of Kochi. LNG imports have not risen as much as the forecast 21 mtpa, although they have grown at a compound annual growth rate (CAGR) of around 9 percent over the last ten years (Figure 4).

Figure 4. LNG consumption (bcm).

Source: Petroleum Planning & Analysis Cell, MoPNG, 2018.

While the PNGRB was required to regulate the setting up of LNG terminals, it was only in 2012 that it was empowered to draw up regulations for LNG terminal licensing. The draft National Energy Plan has suggested that in future open access and regulated tariff provisions under the PNGRB act should be extended to gas offtakers at LNG terminals (NITI Aayog 2017b). While this is a positive move aimed at boosting uptake, especially in the face of tricky negotiations with sourcing companies, it remains to be seen if it will result in higher imports, given the existing demand situation.

According to the projections in Vision 2030 (PNGRB 2013), India's LNG import capacity is expected to reach 73 mtpa by 2021-22 and 83 mtpa by 2030. Table 5 lists existing, under construction, planned and proposed LNG terminals.

Pipeline infrastructure

Believing that the natural gas sector could be a driver of rapid growth in the country, in 2006 the Indian government introduced its Policy for Development of the Natural Gas Pipeline and City or Local Natural Gas Distribution Network (CAG 2014). The key objective of this policy was to attract investment from both the public and private sectors into developing gas pipelines and city or local gas distribution networks. It permitted up to 100 percent FDI through an automatic approval route. Some of the other policy features include:

- Facilitating non-discriminatory open access to pipeline networks for all players under rules to be laid down by the PNGRB.

- Encouraging competition and avoiding abuse of the dominant position by any entity.

- Introducing a build, operate or expand business model for investment in and operation of the pipeline infrastructure, with authorization from the PNGRB.

- 33 percent additional design capacity, over and above the total firmed up and contracted, to be made available for use on a common carrier basis by any third party.

- Provision for offering marketing exclusivity rights for a period to be determined by the PNGRB, but without ignoring consumer interests.

- The need to ensure an arm's length relationship if the developer has business interests in the related areas of gas marketing or city or local gas distribution networks.

While the policy provided some of the needed interventions to facilitate the development of the pipeline industry, it could not address the business risks for developers arising from demand uncertainties, including the possibility that power, fertilizer or a large group of industrial companies might exit as anchor customers. In fact, correlating the current pipeline network to the consumption pattern shows that the northern and western markets, which have the highest consumption at more than 65 percent, also have better pipeline connectivity and import infrastructure. However, some pipeline projects fail to get off the ground because there is no demand or the economics do not work. In 2016, the Oil Industry Development Board (OIDB) provided 40 percent viability gap funding (VGF) as a capital grant for the 12,940 crore rupee (~\$1.85 billion) gas pipeline from Jagdishpur to Haldia and Bokaro to Dhamra, which was a good start. However, much more is needed to create India's gas infrastructure so as to ultimately achieve the ambition of a 15 percent share of natural gas

in the country's fuel mix. In this context, successful experience of reducing demand risks using different and innovative business models for various highway infrastructure projects by the National Highways Authority of India (NHAI) may provide useful lessons for the gas sector. Instead of a flat 40 percent VGF for all gas pipelines, a graded approach of providing VGF support linked to the level of demand risks, as experimented with by the NHAI, in a particular pipeline may be a better way of utilizing the limited financial resources earmarked by a pipeline developer for addressing the risks.

Gas utilization

The limited availability of relatively inexpensive domestic gas is often cited as a major reason for gas rationing to various price-sensitive consumers (PC 2006). The policy was always intended to be ended once the gas supply matched demand. But since actual supply has consistently been below expected demand, the gas utilization policy continues in force. The priority for gas utilization from domestic sources – i.e., APM gas produced by NOCs under the PSC regime and NELP contract – is set by the government and revised from time to time. In the past, the power and fertilizer sectors remained the major beneficiaries of domestic gas allocation by the Gas Linkage Committee or the Empowered Group of Ministers (EGoM). In 2008, the EGoM accorded the highest priority to existing gas-based urea plants, followed by existing gas-based liquefied petroleum gas (LPG) plants and gas-fueled power plants. Supply of gas to city gas projects for the domestic and transport sectors was given fourth priority (LSS 2013).

The fertilizer sector achieved its priority on the premise that the agriculture sector provides a crucial link between the rural, industrial and service sectors of the economy. Similarly, additional power generation using gas would result in increased availability of electricity which would have positive externalities for both the economy and the environment. The LPG sector was prioritized based on the government's policy of supplying LPG at subsidized rates because costlier imports could produce adverse consequences. City gas development in the transportation and domestic segments was included as a result of a Supreme Court judgment directing the government to give priority to the transportation sector, including private vehicles, throughout India to curb the growing air pollution in cities. In 2014, MoPNG proposed a revised gas allocation policy, where public transport – through CNG – and households, through piped gas, were given the highest priority in gas allocation, followed by plants providing inputs to strategic sectors, such as atomic energy and space research. The fertilizer sector was demoted to fourth place. Gas-based power generation was given the lowest priority, despite having significant stranded generation capacity.

One of the main drawbacks of the gas allocation policy has been its insufficient focus on overall cost economics and market forces: it appears to have had only a limited role in realizing the true latent demand from various gas consumers. The main focus has rather been on who gets the gas, at what volume, and at what price. It seems that government control over domestic gas allocation and its changing priorities is spurring demand from different sectors at different points in time.

Regulation – Scope, Challenges and Governing Institutions

An independent regulator and sound regulatory principles are both considered crucial to creating an efficient and competitive market that provides a level playing field for all players and encourages investment while paying heed to the interests of both industry and customers. The gas sector in India is governed by multiple agencies. The institutional structure and key governance issues, such as regulation, competition and the relationship between the institutions, central government and states, across the gas value chain is discussed below.

Institutional structure – policymaking and regulation

There are several different entities responsible for the regulatory side of natural gas (Corbeau 2011).

Besides policy formulation, MoPNG oversees (i) the exploration, production and pricing of oil and natural gas; (ii) refining, distribution and marketing; and (iii) the planning, development and control of, and assistance to, the oil and gas industries. It regulates the allocation and pricing of gas. The Petroleum Planning and Analysis Cell (PPAC) is part of the ministry.

The Directorate General for Hydrocarbons (DGH), established in 1993, is the technical upstream regulator. It has responsibilities for exploration and managing production-sharing contracts. It is also responsible for implementing NELP (now HELP) and CBM policies. Its overall mandate is to “promote sound management of the Indian petroleum and natural gas resources, having a balanced regard for the environment, safety, technological and economic aspects of the petroleum activity.” (MoPNG 1993).

The PNGRB, created in 2006, oversees the midstream and downstream parts of the market. It is independent of the MoPNG, but the government can occasionally give broad direction in the interests of sovereignty and to maintain or increase supplies. Its mission involves protecting consumer interests, but also registering and authorizing companies active in LNG, storage, city distribution and transport. It also regulates transportation access and rates, and access to distribution or city networks. Its overall vision is to create a flourishing energy market, to facilitate the flow of investments, and ensure fair trade practices and competition.

Further regulators in the sector include the Oil Industry Safety Directorate, which is in charge of improving safety standards in the oil and gas industry; the OIDB, created to promote and facilitate the development of the sector and collect cess – a kind of tax levied to finance the development of the oil and gas industry – on the blocks awarded on a nomination basis; the Directorate General of Mines Safety; and the Petroleum Explosives Safety Organization.

Regulatory and governance issues

Upstream

The DGH is frequently referred as an upstream regulator of the oil and gas industry. However, in a reply to the Standing Committee on Petroleum and Natural Gas (2015-16), DGH itself contended that it is not a regulator, but rather a technical arm of the MoPNG, with a role to develop the country’s hydrocarbon resources, “having a balanced regard for the environment, safety, technological

and economic aspects of the petroleum activity” (MoPNG 1993). It has several non-regulatory functions relating to E&P activities. One of the most important functions of the DGH is to undertake geoscientific surveys of various basins and prepare data for E&P companies studying the prospectivity of various blocks. It has carried out a number of geophysical surveys to date, but the coverage and quality of its data remain poor. There continues to be considerable uncertainty over India’s hydrocarbon resource potential since a major part of the sedimentary basin is still either unexplored or underexplored. Proposals have been made for years to improve data collection (Corbeau 2011). One of the recommendations of the Standing Committee on Petroleum and Natural Gas (2014-15, Sixteenth Lok Sabha), was that 46 percent of the sedimentary basin should be assessed for hydrocarbon prospects under the Hydrocarbon Vision 2025. So far, progress on the National Data Repository has been relatively slow.

In the absence of a well-developed national level data repository covering all sedimentary basins, the Open Acreage Licensing Policy that allows developers to select exploration blocks not put up for bidding by the government may not yield the desired outcome. Developers have also faced difficulties in getting the necessary environmental clearances from multiple entities, resulting in a long time-lag between discoveries and production. There is a need for joint coordination between the various ministries – defense, petroleum and natural gas, environment and forest – before awarding a block, to avoid delays in production.

From time to time, various expert groups and committees, such as the Chawla Committee in 2011, have recommended making the DGH an independent upstream regulator. The MoPNG, however, maintained that because the government is the owner of India’s natural resources, the ministry

has an important role to play in their management and development. Also, since policies such as NELP (now HELP) and CBM already provide a level playing field, and since a PSC is signed between the government and the contractor, an independent regulatory body “may not be tenable” (CCEA 2014).

Midstream and downstream

Regulating access to the common or contract carrier and overseeing transportation tariffs are the two key regulatory responsibilities of the PNGRB in the midstream sector. Besides regulating access to city gas or local natural gas distribution network, PNGRB regulates certain aspects of the downstream sector, such as refining, marketing and distribution of petroleum products. Key regulatory and governance issues are described below.

Lack of coherent development

Under the current regulatory framework, private or public players propose new pipelines through an expression of interest, which is then reviewed by the PNGRB. However, this does not seem to ensure the network’s coherent development. For example, proposals for LNG terminals are never linked to proposals for connected or adjacent pipelines. In some cases, the construction of the terminal can proceed without all pipeline issues being resolved. This is the kind of policy that resulted in the Kochi LNG terminal being hardly used – around 5 percent – due to the lack of necessary pipeline infrastructure. Although new pipeline network development is based on the interests of public or private entities, the process lacks a detailed techno-economic viability assessment (Petrofed 2015). This could be achieved through a central agency – possibly a regulator – responsible for the long-term integrated planning of gas infrastructure, taking account of future requirements of the gas-based economy.

While the MoPNG did have plans to build a natural gas grid, planning for it was done on a purely ad hoc basis.

Dual role as transporter and marketer of gas

Although regulatory provisions provide for access to gas pipelines, the existing pipeline companies are both transporters and marketers of gas, leaving little opportunity for external companies to access consumers, even if they may have cheaper gas. In practice, customers have to sign gas sales and transport agreements with the seller, locking them in for years. In 2012, PNGRB suggested unbundling the activities of transportation and marketing through measures such as account segregation, legal segregation, and also recommended a timeline for ownership/management control unbundling (PNGRB 2012a). However, several entities petitioned the regulator, with the established players typically suggesting a slower timeframe, given the lack of development of a mature market, and the newer players and consumers welcoming the move (Gujarat Gas 2012; UPES 2012; IOC 2012; GAIL 2012; H-Energy 2012). However, it had seemed government support for unbundling was not forthcoming, until it was reported in April 2018 that the Indian government was working on unbundling the transportation and marketing of gas (The Economic Times 2018).

Compensating for the investment risks

Developing gas pipeline infrastructure requires huge investment, but customers may pose a significant risk to potential developers/investors in the absence of assured gas availability in a particular gas grid. To overcome these challenges, in 2014 MoPNG proposed the idea of providing VGF to accelerate the construction of gas pipeline infrastructure. To get around the risks associated with demand

uncertainties, one of the pilot projects was made part of GAIL's Jagdishpur-Haldia pipeline project (Jagdishpur-Haldia and Bokaro-Dhamra Gas), and a capital grant of 40 percent of the total estimated project cost was substituted for VGF (MoPNG 2017). Devising an appropriate hybrid cost recovery system is important and requires an appropriate regulatory framework for licensing and determining tariffs to lower the market (or volume) risk for such projects.

Conflicts over mandate

PNGRB is in charge of regulation and markets, and the government is in charge of pricing and allocation. There have been conflicts between what the regulator wants to do and what the ministry would like to do. In 2012, Indraprastha Gas Limited (IGL) challenged PNGRB's powers to regulate its tariffs when the regulator ordered IGL to reduce them by 63 percent, with retrospective effect from April 1, 2008 (PNGRB 2012). The matter was decided in favor of IGL by the Delhi High Court and upheld by the Supreme Court ruling that PNGRB cannot fix the retail price of gas (SC 2017). In addition, section 16 of the PNGRB Act, which gives powers to the regulator to issue licenses for city gas distribution (CGD), was not published by the government for nearly four years, leaving the regulator with limited powers to issue gas distribution licenses.

Maintaining the status quo in terms of the weak and ambiguous mandate of PNGRB may prove a hindrance to the government's vision of developing a gas-based economy. Recognizing the importance of this, MoPNG is considering restructuring the regulator's activities and providing greater clarity on its role as a midstream/downstream regulator, consonant with its vision (Mishra 2017). However, it remains to be seen whether the government will truly empower the regulator.

Pricing – An Important but Complex Issue

Traditionally, India's power and fertilizer sectors have been its main price sensitive gas-consuming sectors. Therefore, the price at which gas is affordable, the price setting mechanism, and who should set these prices continue to be subjects of debate. Received wisdom says that the electricity and fertilizer sectors are so price sensitive that they cannot deal with prices above \$5/MMBtu. This is also the price benchmark quoted by Minister Goyal for future long-term LNG contracts (Singh 2016). There is also the question of pricing mechanisms in different parts of the value chain, in particular the upstream and midstream segments. There also exists a price duality, where prices are partly regulated in the upstream sector, where domestic gas has APM and non-APM price regimes, and partly market linked. Prices for imported LNG are set by global LNG market dynamics, including long-term contracts. While the government has undertaken some price reform measures in the past, prices are yet to reflect market dynamics. Important issues and suggestions are discussed below.

Upstream – price setting mechanism and challenges

There have been many pricing systems for different types of gas, such as conventional gas, high pressure/high temperature (HPHT) gas and coalbed methane in the upstream sector. Upstream gas pricing has been the focus of reforms and changes over the past decades, with the aim of incentivizing upstream gas production while keeping gas prices affordable; two objectives which are not necessarily aligned.

Though the NELP process was supposed to include a price discovery process, this has, however,

remained a nebulous concept (Sen 2015). In particular, the contested price of KG-D6 gas illustrates the complexity of the process. Appendix 2 describes the APM and non-APM price system in more detail. The existence of this dual pricing system has resulted in two distinct gas markets.

In one market, gas produced by PSUs is allocated to specific customers according to the Gas Policy and sold under the terms of the APM set by the government. The price of APM gas was revised first in 2005 and again in 2010 when APM prices were doubled to \$4.2/MMBtu. This level of \$4.2/MMBtu was very close to the price at which Reliance KG-D6 gas was being sold. In the other, non-APM, market, private companies or joint ventures produced gas and sold it at prices agreed according to production-sharing contracts (Corbeau 2011). LNG imports also fell under the non-APM gas price regime. This duality afflicted the gas sector until the late 2014 gas price reform.

In 2014, a new formula setting the reference price for normal domestic Indian gas fields was introduced that linked prices to various international markets, such as gas prices at Henry Hub (for North America), the National Balancing Point (NBP) of the UK (for Europe), Canadian Alberta and Russia (see Appendix 3). Gas prices were increased to \$5.61/MMBtu in October 2014, from the initial level of \$4.2/MMBtu that prevailed since 2010. However, due to low oil and gas prices internationally, gas price levels progressively slid to \$2.48/MMBtu as of 2017 (Figure 5). But they have increased gradually since then, to \$2.89/MMBtu in October 2017 and to \$3.06/MMBtu in April 2018. Figure 5 shows the price evolution since the implementation of this new formula.

Figure 5. Upstream gas prices in India since the 2014 reform.

Source: (i) Petroleum Planning & Analysis Cell, MoPNG; and (ii) The Economic Times 2017.

Note: Deepwater, ultra-deepwater and high pressure-high temperature gas fields are categorized as 'Difficult fields'.

Linking upstream prices with international markets – which have different dynamics and limited similarity to the Indian market – as part of the price reform measures has increased the complexity and uncertainty of price formation and has set a benchmark that is inadequate for developing a competitive market. For example, when prices fell to \$2.5/MMBtu in October 2016, ONGC asked the Indian government to set a floor price as it was receiving prices that were below production costs. In its assessment, each dollar decrease in gas prices reduces annual revenue by 42 billion rupees and profit by 24 billion rupees (The Indian Express 2016). As the revised 2014 gas price does not apply to all gas fields, this produces many price disparities. The positive aspect of the 2014 price formula is that it brings some transparency to the eventual price. Nonetheless, uncertainties remain because too many different prices are used to determine the reference price for India's gas. The

only major change is that the government no longer intervenes in setting the pricing formula, though it did create another one for more difficult fields in 2016.

The need to reform and rationalize the upstream gas pricing mechanism remains. If the pricing regime introduced recently for 'difficult fields based on opportunity costs and linked to imported LNG or fuel oil and coal' is implemented successfully, it may address some of the pricing issues for the gas sector, which is often compared with potential alternatives.

Midstream

LNG imports

India is the world's fourth-largest LNG importer. A substantial share of India's LNG comes from Qatar.

Pricing — An Important but Complex Issue

In 2017, 10.14 mtpa out of 19.22 mtpa came from Qatar (Figure 6). India also imports from a variety of other LNG exporters, notably from Australia and Africa. Prices for imported LNG are mutually negotiated, and price indexation over the contract duration has followed a variety of approaches.

When the first contract for importing 7.5 mtpa of LNG was signed between India and Qatar, it was one of the largest LNG contracts at the time, and the fundamentals were weak. However, the contract was a big achievement for India as the gas was available for five years at \$2.5/MMBtu. It should be noted that, while this price level seems low today, when the contract was negotiated in the early 2000s it was within the range of prices agreed. It was estimated that India saved around \$14 billion of equivalent subsidy because the LNG price was fixed for the initial contract period.

But when the price increased after the initial five years, customers complained, especially as

the price formula included a 60-month moving average of the Japan Crude Cocktail (JCC) price. When, in 2015, India's LNG costs under the deal reached around \$13/MMBtu, demands for contract renegotiation became more pressing as this price was substantially higher than spot market price levels which ranged around \$6-7/MMBtu. At the end of 2015, Petronet LNG was able to renegotiate the formula of the initial Qatari contract to achieve a price formula that was more in line with the spot market price. It also increased the agreed quantities by 1 mtpa from 2016 until 2028 to keep overall revenue flows to Rasgas at around pre-negotiation levels. Petronet LNG also signed a long-term contract (1.44 mtpa) with Australia's Gorgon LNG project for 20 years, which was also indexed to the price of Japan's crude oil imports. This contract was also subsequently renegotiated and is now indexed to 13.9 percent of prevailing Brent oil price instead of 14.5 percent of the price of Japan's crude oil imports. Meanwhile, GAIL has contracted LNG from Gazprom Marketing & Trading of Russia and

Figure 6. India's LNG imports: long-term contracts against short-term contracts/spot LNG.

Source: The International Group of Liquefied Natural Gas Importers (GIIGNL).

from the U.S., but the company has been reselling parts of those volumes or swapping them due to the absence of opportunities in India's downstream market (Verma 2017).

There has been a buyers' market since 2015, enabling buyers to achieve better conditions than a few years ago. Creditworthy buyers with long-term demand perspectives are also becoming very rare, and India is not an exception – particularly in terms of gas demand uncertainties. But Indian customers may not even perceive current prices in the Asian LNG market to be low enough. These have been hovering between \$4 and \$7/MMBtu during most of 2016, spiking at \$11/MMBtu during the winter of 2017 due to increasing Chinese LNG demand. However, Minister Piyush Goyal, when in charge of power, was happy for India to buy more LNG, though he stipulated it must be at \$5/MMBtu (The Hindu Business Line 2016) as the price for the end-user will be much higher than the price it arrives at at the LNG terminal (see downstream section). The higher end-user price is one of the greatest difficulties that GAIL has encountered in marketing its U.S. LNG to Indian customers. When it was contracted in 2011, this LNG purchase looked good compared with oil-indexed LNG at \$100/bbl, equivalent to LNG prices of roughly \$14-15/MMBtu. Now U.S.-contracted LNG does not look so affordable at around \$8/MMBtu. Buyers prefer to take short-term LNG because there is a perception that LNG prices will remain low for a long time, and, if not, that LNG could be made available at fixed prices. This follows the announcement by Charif Souki, chairman of U.S. natural gas company Tellurian, that U.S. LNG could be delivered at \$8/MMBtu to Japan for a period of five years after 2023 (Fisher 2017).

If India is to achieve a gas-based economy, importing LNG will be crucial, so contracting it is

becoming a critical issue. As of now, slightly less than half of India's gas imports come from the spot market because of the low spot price, while around 50-60 percent are on long-term contracts ranging from 10 to 25 years. The key question for Indian LNG buyers now is how best to optimize their portfolio, with supply contracted through a mix of long-term contracts (defined as longer than four years), short-term contracts (less than four years), and spot market gas.

Pipelines

The PNGRB sets pipeline tariffs, including those for trunk and spur lines, following the principles defined in the Determination of Natural Gas Pipeline Tariffs Regulations 2008. These give rise to the following issues:

- The additive nature of pipeline tariffs means they are becoming increasingly unaffordable to customers.
- Revenues depend on the actual volume flowing through the networks.
- There is no revision of the tariff through the lifetime of the project.

Reliance's East-West pipeline helps illustrate the implications of the zonal transmission tariff structure (Figure 7). For Reliance it would mean charging different transmission charges for gas consumers in Andhra Pradesh, Maharashtra and Gujarat. Consequently, under the zonal entry-exit tariff system, consumers located near the intake point, or the source of gas injection, will pay lower transmission charges than those located further away. Likewise, if Dabhol Power Plant had to source its gas supply from KG-D6, instead of from sources on the west coast, using the EWPL pipeline, the delivered cost of gas would likely upset

Pricing — An Important but Complex Issue

Figure 7. Illustration of zonal pipeline tariffs for Reliance's East-West pipeline (length 1,469 km).

Source: PNGRB Public Consultation Document (PNGRB 2014a).

its economics due to the high transmission charges under the zonal price regime transmission. CNG/ piped natural gas consumers would be affected similarly. Electricity producers have also criticized a proposed point-to-point tariff system for every entry/exit pair within the system, arguing that though gas may not flow through the agreed contractual path, buyers have to pay the rates fixed under this methodology, which increase every 300 kilometers. Explicit and cost-reflective tariffs have been called for, which could reduce the delivered cost of gas

for some power producers. For the same purpose, electricity producers have suggested a commodity swap, which might help to stabilize end-user prices.

GAIL, with a share of almost 90 percent of the gas pipeline infrastructure, has suggested simplifying tariff-setting by prescribing a single 'postage stamp' rate, uniform across both geographies and consuming segments. Under this proposed tariff model, overall capital expenditure and operating expenditure would be pooled and distributed over

the volume of the inter-connected natural gas pipeline system.

Besides simplifying the complexities of the existing zonal tariff model, the proposed tariff could promote the equitable distribution of gas and facilities, leading to uniform gas-based economic development across the country.

Under the current bidding mechanism, developers are exposed to significant market risk as revenue recovery depends upon the actual volume of gas transmitted through the networks at the tariff quoted during the bids. There is another issue of power producers not taking the gas they regard as uncompetitively priced, something which is beyond their reasonable control; current regulation does not provide for subsequent adjustment of tariffs. The revenue recovery risk has severely impacted investment in gas infrastructure and, as a result, no significant progress has been made on the ground despite several authorizations being issued. Many countries considering building pipeline infrastructure use an 'open season' or 'pre-auction capacity booking' to evaluate market interest – or lack of it – among prospective shippers. This enables them to adapt the volume of the planned pipeline project and finalize the technical specifications of the project such as capacity and size. Typically, regulations across many gas markets allow developers to modify or 'clawback' the tariff assumptions periodically.

Midstream taxation system

For end-users, a number of taxes are also added on top of the wholesale price of gas – for upstream gas or imported LNG – including a route-dependent pipeline tariff and a marketing margin. In particular, natural gas faces a patchwork of taxes all along the line, from the moment it enters India to when it reaches the end-user. These components include

an import duty on LNG, purchase taxes levied by the different states crossed by the gas pipeline, and finally the value-added tax (VAT) on all the previous elements. Taxes can vary substantially from one state to another. This means that even from a starting price of \$5/MMBtu for imported LNG, the end-user might pay twice that amount. Appendix 4 provides a sample calculation to illustrate the impact of applicable taxes on the delivered cost of gas for a power plant.

Another contentious issue is that these taxes may treat gas less favorably than competing fuels. The logic and methodology behind different service tax regimes in different states vary from fuel to fuel. Before tax regime changes in 2017, most states – Madhya Pradesh, Maharashtra, Andhra Pradesh, Uttar Pradesh, Tamil Nadu and Gujarat – were levying low service tax/VAT rates of 4 to 5 percent on coal and coke, in addition to an average 6.8 percent of excise duty. However, the effective rate of about 11 percent was reduced to 5 percent after the implementation of the new Goods and Services Tax (GST) reform by the government in July 2017. By contrast, taxes in Gujarat and Uttar Pradesh remained as high as 15 percent and 26 percent respectively for regasified liquefied natural gas. Such a taxation regime will encourage the use of coal rather than gas. By reducing its taxes under GST, the government wants to make coal-based power generation more affordable for the vast majority of subsidized consumers (The Economic Times 2017a). On the other hand, high taxes on an environmentally benign fuel like natural gas look like rent-seeking behavior by various state governments. In 2015, when Andhra Pradesh extended the VAT exemption on gas for two years, the decision was expected to result in a revenue loss of 23 billion rupees (about \$0.36 billion) to the government for the two-year period (The Times of India 2015).

The Indian government introduced its 2017 GST transformational tax reform with the objective of replacing various existing direct and indirect taxes. However, five fuels – crude oil, natural gas, aviation fuel, diesel and petrol – were excluded during the initial year and will continue to follow the earlier tax regime. By contrast, coal is included. So unless the price of imported LNG drops further, the current taxation regime will make the delivered cost of natural gas to consumers more expensive, affecting

their commercial viability, particularly for users in the electricity sector.

Some reform of the current tax regime is clearly required to increase the share of natural gas in India's energy mix and support a transition towards the government's vision of a gas-based economy. There is a need for taxation to recognize the merits of gas as a less carbon-emitting fuel to harmonize taxation across the states, and to treat gas equally compared with other fuels.

Changing Preferences of Anchor Gas Consumers

Power generation

From government projections, gas-based power generation is likely to account for around 46 percent of gas demand by 2026-27 (Figure 8). However, with the prevailing price dynamics of regasified LNG (R-LNG), a significant amount of India's existing 24 gigawatts (GW) of gas-fired generation capacity is either sitting idle or poorly utilized. As retail electricity rates continue to be priced below the cost of supply, utilities are not purchasing power from gas-based power generation because of its higher variable cost compared with coal. Some industry experts, however, question the future for natural gas in the power sector as it is squeezed by coal and renewables. However, the fast-growing deployment of intermittent renewables in India could lead to an increased role for gas-based power generation for balancing purposes.

Industry players also predict that energy storage will become an economically viable option for household electricity consumers in the next five to eight years. If that happens, it will be a game changer and could potentially affect the appropriateness of gas-based generation, even for meeting peaking requirements. At the moment, given the significant gas-based power generation capacity already available, experts feel that new investment in peaking capacity may not be required in the near future. Efforts were made to revive this stranded generation capacity, which did increase gas demand, but the scheme for utilizing stranded gas-based projects was halted after two years in early 2017. Policy uncertainties of that sort mean that the government is seen to be giving mixed messages to prospective gas sector investors as to whether or not India's power sector will remain a major consumer of gas in future.

Figure 8. Historical and projected gas demand, by sector.

Source: (i) Petroleum Planning & Analysis Cell, MoPNG; (ii) BP Statistical Review-June 2018; and (iii) Vision 2030.

City gas

City gas was the fourth largest consumer of gas in India in 2016-17. Despite its substantial market potential, it is not expected to grow significantly due to the lack of proper infrastructure. 406 bids have been received in the recently concluded (July 18, 2018) ninth bidding round for CGD, covering 86 geographical areas spread across the country, in an effort to boost consumption in that sector. Once the development licenses are awarded, this initiative is expected to attract investment of about 700 billion rupees. However, prospective CGD developers may face additional risk if a transmission pipeline does not yet serve the licensed areas.

Transportation

Gas could also work for transportation, but in that sector it faces infrastructure-related challenges similar to those of CGD. Although gas as a transportation fuel has marginal value creation due to lower emissions and a lower price than gasoline (petrol), cities with city gas networks have seen only limited vehicle conversions to gas from liquids

because of the perceived gas price uncertainty and inconvenient access at retail stations (PwC 2016). Also, people will not be ready to move to CNG-based cars or scooters until these are sufficiently promoted and made to seem more attractive.

Industrial sector

Refining, petrochemicals, fertilizer, LPG, sponge iron and steel are the major users of gas in the industrial sector, together accounting for nearly 63 percent of the 139 MMscm/d of gas consumption in 2016-17. Use of gas as a feedstock by fertilizer plants is likely to decline from 31 percent in 2016-17 to 17 percent by 2026-27. There are plans to expand refining capacity into the next decade, which will make moderate growth in demand possible depending upon the adequate delivery of gas and its price competitiveness. The petrochemical sector is also likely to show moderate growth in the future. However, that will depend on improving the country's overall business environment to create demand from the textile, automobile and food packaging industries (Cornot-Gandolphe 2018). Gas demand in iron and steelmaking is expected to be muted due to the increasing use of blast furnaces in the steel industry.

Conclusion

India is transitioning from a coal-based economy to one using cleaner energy sources. Natural gas could speed this transition by becoming the fuel of choice in sectors such as industry and city gas, where fuel substitution by renewable energy sources is either difficult, due to the variable nature of these sources, or unfeasible. However, to achieve this, there needs to be a concerted effort involving multiple measures to improve the utilization of natural gas. This report has presented a series of measures that could assist in increasing the share of natural gas in the energy mix by 2030 and bring about India's vision of a gas-based economy.

The nature of the Indian gas market, where some aspects are liberalized and some aspects are controlled, together with frequent government intervention in the form of multiple policies and regulations, has not encouraged competition. This has had a detrimental impact on the entire natural gas supply chain. It has led to weak production growth, rent-seeking behavior in transmission, and an overall decline in the relative share of gas in primary energy consumption. Moreover, frequent changes to national policy as well as to regulations have favored the PSUs, supporting the status quo in the structure of the gas market, and diminishing investor confidence in the gas sector. All these factors point to a need for stable and consistent natural gas policies. That would send the right signals to investors, which would boost the share of private participation in the sector. But policies alone will not increase private participation. The outcome of the NELP rounds has proved that without easing the regulatory burden and shortening the time required for approvals, private sector participation will not increase. Though the government has changed its overall policy on block allocation with the introduction of the HELP, the convoluted regulatory procedure and lengthy approval time have still not diminished. Auctions can be conducted

with more ease and transparency under the Open Acreage Licensing Policy, but upstream production continues to be plagued by procedural hurdles.

The midstream sector continues to be subject to the 'chicken and egg' problem of demand versus infrastructure. Non-state involvement in pipeline infrastructure has been limited despite regulations allowing for private participation. One way to resolve the 'which comes first' problem is to look at creating infrastructure capacity without linking this to firmed up contracts. This holds true for regulations covering both pipeline infrastructure and LNG terminals. In a perfect market, the risk of building infrastructure with or without firmed up contracts would be reflected in the cost of debt. In a controlled environment, such a clause has proved a handicap to creating infrastructure capacity. However, if the revision of this clause turns out to be difficult, then there needs to be a mechanism for private companies to cover their investment risks through other measures, such as viability gap funding. Moreover, a national policy on the creation of gas infrastructure would also help private companies prepare their strategies, seek consumers in designated zones and plan funding options.

The duality in the Indian gas sector of the 'liberalized' production process and the controlled cost of supply has had a significant impact on the availability and consumption of natural gas. While tariff-setting for domestic gas has not been particularly successful in attracting new gas investments, it has resulted in an increase in gas consumption. However, it has also created an artificial boundary between the use of domestic gas and LNG. The share of gas in the Indian energy basket will not increase without significant pricing reforms. This will mean the government's disengaging from setting gas prices, taking into account rising costs of production and getting rid of

Conclusions

the current mechanism which links Indian gas prices to other markets and not to domestic consumption. Creation of a gas hub should not be seen as a solution, given the existing challenges in physical and digital infrastructure.

More effective price discovery could ultimately result in an increase in the domestic gas supply which would expand overall consumption. However, such a move could impact price sensitive sectors such as fertilizer producers and power generators. Consequently, there needs to be an adequate mechanism to protect these sectors from higher gas prices. The gas pooling scheme in the fertilizer sector has proved to be a success. In the power sector, an increase in Clean Energy Cess – a kind of carbon tax levied on the consumption of coal to finance and promote various clean environmental initiatives, including renewable energy – or adding the cost of negative externalities caused by coal mining to the cost of landed coal, could make

gas a more attractive proposition. Moreover, further reforms in power markets, introducing peaking power regulations and having different tariff structures for ramping up and peaking power could, ultimately, aid the gas sector, since gas-based power is more suited to providing ramping up capacity than coal is. Another means of making gas more attractive, especially in the power sector, would be to reduce the input costs by having a uniform taxation structure for natural gas across all of India's states.

Natural gas can be a viable option for India only if the government takes a decisive and consistent role. The key messages in this report are an attempt to consolidate the various issues impacting the sector and to propose limited implementable solutions. However, a concerted effort will need to be undertaken by different governing bodies and parties in order to make India's vision of a gas-based economy a reality by 2030.

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Appendix 1

Existing and planned gas pipelines (March 2018)

Figure 9. Existing and planned gas pipelines (March 2018).

Source: Abstract from Chapter-5 Major Pipelines in India, PPAC Ready Reconer, 2018.

Appendix 2

India's APM and non-APM gas pricing system

The government sets the price of Administered Pricing Mechanism (APM) gas and applies it to specific gas fields operated by state-owned oil companies ONGC and Oil India. The gas is sold to fertilizer plants, power plants, specific end-users covered by court orders and small-scale consumers that have allocations up to 0.05 million cubic meters per day (Mcm/d). In July 2005, the price of APM gas was increased from 2850 rupees per thousand cubic meter (\$1.59/MMBtu) to 3200 rupees per thousand cubic meters (\$1.79/MMBtu), except in the northeast region where gas was sold at 60 percent of the revised price, i.e. 1,920/1,000 rupees per cubic meter (\$1.07/MMBtu) (Corbeau 2011). During that time, the share of APM gas production decreased, while the share of more expensive non-APM gas supplies increased. This situation put pressure on the government to change the level of APM gas prices. The reform was delayed, however, until May 2010, when APM prices were doubled to \$4.2/MMBtu, except in the northeast region where gas was sold at 60 percent of this new price. This level of \$4.2/MMBtu was very close to the price at which Reliance KG-D6 gas was being sold. The government also gave marketing freedom to ONGC and Oil India for additional gas to be produced at market rates.

Non-APM gas prices cover different types of gas: gas sold under PSCs dating from the pre-NELP regime, gas sold under PSCs from the NELP era and LNG. PSCs predating NELP include, for example, gas from the Panna Mukta Tapti and Raava fields. The price for those fields was linked to the 12-month average of fuel oil prices and was typically higher than APM gas (Corbeau 2011). Gas sold under PSCs from the NELP regime has a

different pricing system, in which the contractor was required to sell the gas at a competitive arm's length price to the benefit of both parties – the government and the contractor – according to the PSC. This specifies that gas which is sold to the government or any other government nominee shall be valued on the terms and conditions actually obtained, including the pricing formula and delivery, while gas which is sold otherwise shall be valued on the basis of competitive arm's length sales in the region for similar sales under similar conditions. In addition, the government must approve the price formula, but no clear guide was given as to how to determine it in practice. The government was the judge but also a kind of party to the deal: on the one hand, it had an interest in seeing gas being sold at a low price for the benefit of the Indian economy, but on the other hand, it was also receiving revenues based on it in the form of taxes and royalties.

The NELP process was supposed to include a price discovery process, which has, however, remained a nebulous concept (Sen 2015). In particular, the contentious price of KG-D6 gas illustrates the complexity of the process. Reliance (RIL) initially offered 12 Mcm/d of gas at the price of \$2.34/MMBtu for 17 years to NTPC and 28 Mcm/d to stakeholder RNRL, another RIL group company, under similar conditions. However, RNRL challenged the decision to increase the gas price from \$2.34/MMBtu to \$4.2/MMBtu, which led to years of legal battles before the state had to finally intervene (Sen 2015, Petrotech 2017).

The government rejected RNRL's suggested price on the grounds that it was not derived on the basis of competitive arm's length sales in the region for similar sales under similar conditions. RIL invited bids for the value of a constant (C) and volumes from companies. Following the bids, RIL proposed a final oil-linked gas price formula:

Appendix 2

$2.5 + (CP - 25)^{0.15}$, whereby C was set at 2.5. CP represents the average price of Brent crude oil in U.S. dollars during the previous financial year, based on the annual average of the daily high and low quotations of the Free On Board Brent price published by Platt's Crude Oil Market wire. It was

decided to cap CP at \$60/bbl – the government revised down the ceiling of \$65 – with a floor of \$25/bbl. For prices above \$60/bbl, which was often the case when the field started producing, this meant a price of \$4.2/MMBtu, which would be valid for the first five years of production, from 2009 until 2014.

Appendix 3

New domestic natural gas pricing guidelines, 2014

In 2012 a significant change in pricing mechanism was announced when the government created the Cabinet Committee on Economic Affairs (CCEA), under the Chairmanship of Dr. C. Rangarajan to review the upstream fiscal regime and the gas pricing system (Sen 2015). The committee was to come up with a new price formula for domestic gas. The initial proposal involved a 12-month average of two components: the volume weighted average of market-priced gas from U.S. Henry Hub, U.K. NBP and Japan's JCC – priced on a netback basis since the country is an importer – and the volume weighted average of producers' netback prices for Indian LNG imports. At that time, expectations were of a doubling of domestic gas prices. This was supposed to reflect a move away from the oil linkage to market forces, except that instead of leading to price discovery it used prices from other gas markets (Sen 2015). One of the biggest worries at that time was that it would significantly increase – almost double – the level of upstream gas prices, with dire consequences on downstream prices (Reuters 2013).

However, as India faced a period of elections in Spring 2014, the reform was postponed many times until October 2014. The government then implemented a revised version of the initial proposal: it removed LNG netback import prices but included other international gas prices, such as the Canadian Alberta reference price and the Russian domestic gas price. This would set the reference price for normal domestic Indian gas fields. Gas prices have been revised every six months since then. Prices are expressed in gross calorific value (GCV),

creating some possible confusion when other prices are expressed net. Gas prices were initially increased to \$5.61/MMBtu in October 2014, from the initial level of \$4.2/MMBtu that had prevailed since 2010. However, gas price levels had been progressively sliding to \$2.48/MMBtu as of 2017 due to low international oil and gas prices (Figure 9). However, they have increased progressively since then, to \$2.89/MMBtu in October 2017 and to \$3.06/MMBtu in April 2018.

The formula to determine the gas price, agreed in 2014 by the CCEA (2014) will be:

$$P = (VHH PHH + VAC PAC + VNBP PNBP + VR PR) / (VHH + VAC + VNBP + VR)$$

Where

- (a) VHH = Total annual volume of natural gas consumed in the U.S. and Mexico.
- (b) VAC = Total annual volume of natural gas consumed in Canada.
- (c) VNBP = Total annual volume of natural gas consumed in the EU and former Soviet Union, excluding Russia.
- (d) VR = Total annual volume of natural gas consumed in Russia.
- (e) PHH and PNBP are the annual averages of daily prices at Henry Hub (HH) and National Balancing Point (NBP), less the transportation and treatment charges.
- (f) PAC and PR are the annual averages of monthly prices at Alberta Hub and Russia, respectively, less the transportation and treatment charges.

Appendix 4

Impact of taxes on the delivered cost of gas for power plant users, a sample calculation

The final gas price for domestic users is made up of a high tax component: a route-dependent pipeline tariff and a marketing margin, on top of the wholesale price of gas – both upstream and LNG import prices. In particular, natural gas faces a patchwork of taxes all along the line, from the moment it enters India to when it reaches the end-user. These components include an import duty on LNG, purchase taxes

levied by the states the gas pipeline crosses, and finally the VAT on all the previous elements. Taxes can vary substantially from one state to another. This means that even from a starting point of \$5/MMBtu for imported LNG, the end-user might pay twice that amount, as in the example below.

Based on the example below Table A1, taxes represent \$2.67/MMBtu or 29 percent of the final delivered price of gas for electricity producers. However, for other categories of power generation, this would add another \$0.13/MMBtu for users that have to pay import duty.

Table A1. Price buildup for gas for power generation (example).

Origin: LNG terminals in Gujarat	Particulars	Notes
Consumption: NTPC power plant in zone 4 (Auraiya, Dadri and Faridabad)		
Gas price on GCV basis (including re-gasification) (a)	5.16 \$/MMBtu	
Import duty on LNG for power generation (b)	0	2.5% for other consumers
Gujarat purchase tax @15% levied on a+b = c	0.77 \$/MMBtu	
Marketing margin (d)	0.19 \$/MMBtu	
Transportation charges (e)	1.18 \$/MMBtu	
VAT on gas in Uttar Pradesh @26% levied on a+b+c+d+e	1.90 \$/MMBtu	
Delivered gas price on GCV basis	9.20 \$/MMBtu	

Source: KAPSARC.

Notes

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About the Project

KAPSARC, in collaboration with The Energy and Resources Institute (TERI), India, initiated this project to achieve the following:

- To understand and analyze the current issues in the Indian gas industry's value chain, with the objective of providing policy-relevant suggestions.
- To understand the future of natural gas in India's energy market, with the likely displacement of oil products if gas use takes off, and the potential implications for energy imports.

In terms of scope, the study covers the upstream segment, natural gas transportation infrastructure, liquefied natural gas, import capacity, gas allocation and pricing policies and regulation from upstream to downstream. An extensive review and analysis of the existing literature was carried out as part of this project's research methodology, to synthesize and analyze the relevant issues affecting the gas industry, and to identify gaps in research. A detailed questionnaire was then developed, pre-tested and shared with the stakeholders. Subsequently, consultations with a variety of stakeholders – including government, public sector undertakings, private players, key consumers, industry forums and research organizations – were held to solicit their views on a range of issues affecting the development of an effective and competitive gas market in India.

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