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Natural Gas in India: An Analysis of Policy*

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LIST OF ABBREVIATIONS

APM	Administered Pricing Mechanism
BCM	Billion Cubic Metres
CNG	Compressed Natural Gas
DGH	Directorate General of Hydrocarbons
EGoM	Empowered Group of Ministers
GDP	Gross Domestic Product
GAIL	Gas Authority of India Limited
GSPC	Gujarat State Petroleum Corporation
GWh	Gigawatt Hours
HVJ	Hazira–Vijaypur–Jagdishpur
IEP	Integrated Energy Policy
IHV	India Hydrocarbon Vision
IOC	International Oil Companies
IPI	India–Pakistan–Iran pipeline
KG	Krishna Godavari
kgoe	Kilograms Oil Equivalent
kWh	Kilowatt Hours
LDO	Light Diesel Oil
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LSHS	Low Sulphur Heavy Stock
mmscmd	Million Standard Cubic Metres per Day
MMT	Million Metric Tonnes
mtoe	Million Tonnes of Oil Equivalent
mmbtu	Million Metric British Thermal Units
MMTPA	Million Metric Tonnes Per Annum
MW	Mega Watts
NELP	New Exploration Licensing Policy
NOC	National Oil Company
NTPC	National Thermal Power Corporation
OIL	Oil India Limited
ONGC	Oil and Natural Gas Corporation
PNG	Piped Natural Gas
PPA	Power Purchase Agreement
PPP	Purchasing Power Parity
PSU	Public Sector Undertaking
RGTIL	Reliance Gas Transportation Infrastructure Limited
RIL	Reliance Industries Limited
RNRL	Reliance Natural Resources Limited
scm	Standard Cubic Metre(s)
TAPI	Turkmenistan–Afghanistan–Pakistan–India
tcf	Trillion Cubic Feet

APPROXIMATE CONVERSION FACTORS

International Energy Agency

Mass/ Volume / Heat

1000 cubic metres = 35.314 mmbtu (based on a typical calorific value of 1000 btu/cubic foot)

1 metric tonne = 1360 standard cubic metres

Ministry of Petroleum and Natural Gas

Natural Gas to Crude Oil/ Oil Equivalent

1 bcm = 0.90 mtoe

Currency

1 US$ = Rs 48*

**Apart from instances where historical exchange rates have been used*

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1. Introduction

India is in transition. It is moving from a planned economy with extensive central controls, to one based increasingly on the operation of market forces. Although economic liberalisation began in 1991, its cumulative impact became visible mainly in the second half of the last decade, as India emerged to become the world's fourth-largest economy (in PPP terms) with GDP growth rates averaging 8 per cent per annum. The focus of Indian economic policy has long been on making basic goods and services accessible to the poor. India is now in the process of developing its own social market economy to deliver these more efficiently, but there are certain functional characteristics of the delivery process that are unlikely to change very quickly. This has led to a mix of different systems, and has influenced the functioning of economic sectors in ways that are often at variance with international expectations.

Nowhere is this more apparent than in the oil and gas sector. While the oil market has now been liberalised, even at the level of retail prices, the gas market is still in a state of transition. There are three main factors behind this; (1) the natural sequencing and development of domestic indigenous supply,[1] (2) the more general movement of the economy from socialist planning towards reform and reliance on market forces, and (3) global developments – particularly the increasing availability of LNG, as well as changes in international energy prices, and new policy agendas such as climate change.

A relatively 'young' fuel in the energy portfolio, gas has in the past been delivered to final consumers at 'administered' prices that are far lower than the costs of production, using a system of differential pricing. This is a strategy that has been followed in most commodity sectors of the economy in which the State has a sizeable presence. These subsidies have often been unsustainably high, borne disproportionately by public sector companies, and often failed to directly benefit those at whom they were targeted. This has led to considerable economic distortions, and the build-up of these over the years has led to a dilemma that is now faced by the Indian government in virtually every economic sector; namely, how to encourage the market-oriented provision of goods and services, whilst ensuring their accessibility to the poorest sections of the population.

Significant policy changes have been carried out during 2010 and the first part of 2011, which point to a potentially greater role for gas in the future. In May 2010, the price of 'administered' gas was more than doubled from its previously subsidised level; from US$ 1.8 per mmbtu to

[1] By 'domestic' supply (or domestic gas) we mean gas produced within India, by national and private companies.

US$ 4.2 per mmbtu.[2] This move, whilst signalling a shift towards gas pricing based on economic principles, mirrored the core policy conflict – whilst it appeared to signal the reduction of distortions on one side of the policy equation (that is, the price paid to gas producers by marketing and retailing companies), it highlighted the distortion on the other side (that is, the complex subsidy regime for prices paid by some gas users to retailers).[3] In February 2011, the Federal government, in its National Budget, announced a policy intention to provide the subsidy on fertilisers, one of the largest existing and future potential consumers of gas, via a direct transfer to eligible end-users in the agricultural sector, rather than through the continuation of low-priced gas inputs to consuming sectors, beginning from 2012.

In this paper, we argue that the transition in the gas sector in India is part of the larger movement of the economy from a centrally planned and administered system to a market oriented system. Sections 2 and 3 of this paper set out the background and context for this main argument, by reviewing the evolution of India's energy policy, and the influence of political economy on policy in the hydrocarbons sector. In Section 4, we discuss 'official' forecasts of demand and supply, and suggest that these are subject to the important limitation of being carried out with a 'planner's outlook'. Section 4 also discusses the system of 'balance' that has been sustained between the demand and supply sides in the gas sector (although in reality they are each influenced by separate factors), through India's complex system of allocation and pricing, which has led to significant economic distortions. In Section 5, the paper analyses the main factors that have led to this system – the gas utilisation policy, which has its roots in the quantitative planning system (with an emphasis on quotas), and its recent revival under the New Exploration Licensing Policy regime. In Section 6, the paper argues that the potential for gas cannot be assessed purely through forecasts, but through an analysis of its price competitiveness with alternative fuels in the main consuming sectors.

In Section 7, the paper concludes by arguing that there are specific areas of policy that require review, in order to resolve existing distortions in the system, and to move forward from the 'half way house'– on the supply side, these include a review of specific terms of the fiscal regime in exploration and production, and a need for a commercially sound basis for producer prices of gas and for formal regulation in infrastructure. On the demand side, in suggesting ways forward, the paper draws from experience in the oil sector, where prices were freed for all but the poorest

[2] The US$ 4.2 per mmbtu is the 'market' price of gas that was arrived at by Reliance Industries Limited (RIL), a private gas producer, for its 'KG-D6' production block in the eastern offshore basin. The price was arrived at through a price discovery process under the provisions of the New Exploration Licensing Policy (NELP) of the late 1990s.

[3] This is a broad explanation of recent changes in the pricing system; however, the system remains extremely complex when one accounts for factors such as differential taxes at the state level, and for cross subsidies between industrial and other consumer sectors.

category of consumers; in addition, a pilot scheme providing subsidies on LPG and kerosene directly at the point of distribution is being designed – effectively, potentially replacing the system of subsidising both the input (crude oil) and outputs with a direct subsidy on output (mainly LPG and kerosene), for specific categories of consumers. The paper finds that the distributional objectives appear to be particularly important in the fertilisers sector, and, based on an assessment of the potential for gas in other sectors (including power and city gas), the paper argues that there is a case for market prices to be considered in other gas-using sectors, even if direct subsidies to the fertiliser sector are continued. In the longer term, there is a case for the subsidy to fertilisers to be provided through a direct transfer to the end user.

2. Energy in the Indian Economy

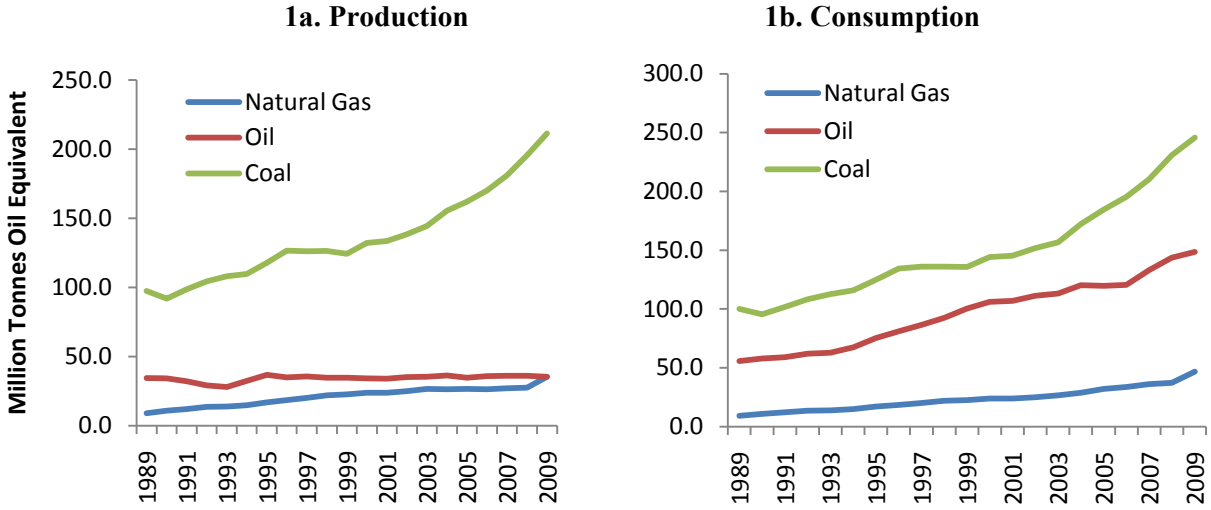
India is essentially a 'coal economy', as it has vast indigenous reserves. Figure 1 shows trends in the production and consumption of three main sources of primary energy over 1989 to 2009.

After coal, oil forms a significant proportion of primary energy consumption. Around 70 per cent of oil is imported and the import bill has been increasing since 1990, when domestic oil production plateaued.[4] India is, however, a *net exporter* of petroleum products, with an overall refining capacity (though not production) of 180 MMTPA in 2009.[5] Approximately 500,000 barrels of oil per day or 25 mtoe of crude oil and products is thus re-exported through product exports.

Although gas forms a relatively small proportion of primary energy production and consumption, its share has been increasing, particularly with the liberalisation of oil and gas exploration in the 1990s, and with the start of LNG imports in 2004.

Figure1: Production and Consumption of Coal, Oil, and Natural Gas, 1989–2009

(Million Tonnes of Oil Equivalent)



Source: BP Statistical Review, 2010

Rapid economic growth has led to growth and diversification in energy use. Plans are also in progress to develop non-conventional energy. India implemented a programme of nuclear energy in 2008, based on the 2005 India–USA agreement on civilian nuclear technology transfer.[6] Expansion in grid connected renewable capacity (solar and wind) is planned by 2022,[7] as part of India's

[4]Domestic oil production picked up again in the 2000s, but high oil prices have kept the oil import bill high; the oil import bill was roughly US$ 70 billion in 2008.
[5] The refining sector was liberalised in the 1990s.
[6] Since the signing of the agreement, the Nuclear Power Corporation of India Ltd is said to be adding 63,000 MW of nuclear energy by 2032, which will be 8 per cent of projected total installed capacity of between 800,000–950,000 MW.
[7] Includes 20,000 MW of solar energy.

voluntary targets on climate change. Significant potential exists for hydro energy, but this has not fully developed due to controversial property rights and resettlement issues. Despite growth and diversification, per capita energy consumption in India is very low, at 529 kgoe, or roughly 30 per cent of the world average.[8] A large proportion of the population lacks access to any form of modern commercial energy, and 80 per cent of the rural population use some form of non-commercial energy; particularly, biomass (Planning Commission, 2006).

Table 1: Primary Energy Mix, 2009

Fuel Type	Percent
Coal	53.50
Oil	31.32
Natural Gas	8.52
Hydro	6.00
Nuclear	0.80

Source: BP Statistical Review, 2009
Note: Figures may be subject to small variation

Four factors have contributed to low per capita consumption. First, capacity constraints have restricted demand and diversification despite early signs of an impending shortage (both peaking and overall) in the power sector, one of the largest energy consumers.[9] Most planned additions to power supply have long lag times to completion.

Table 2: Share of Fuel in Total Installed Power Generation Capacity, 2010

Fuel Type			%
Thermal		**64.7**	
Of which:	*Coal*		*53.3*
	Natural Gas		*10.5*
	Oil		*0.9*
Hydro		**24.7**	
Nuclear		**2.9**	
Renewable Energy Sources		**7.7**	

Total Generation Capacity: 164, 508 MW;
Source: Ministry of Power; *Note:* Figures may be subject to small variations

Second, significant bottlenecks exist in coal, due to its high ash content, and the lack of technology in state-owned companies to mine coal at greater depths. As a consequence, coal imports have been increasing. Table 3 shows this (as it is based on data from 2007, it does not take into account rapid increases in gas production from the eastern offshore Krishna Godavari basin, which began in 2009).

[8] World Bank development indicators.
[9] Several large planned power generation projects failed in the mid 1990s (for example, the Enron Dabhol Power Plant). Policymakers failed to put in place alternatives to ensure that these planned additions to power generation capacity took place. This indicated that a deficit would emerge in the near future.

Table 3: Percentage of Energy Use Met by Domestic Production

	1980–81	1990–91	2000–01	2011–12*
Coal	99.7	97.8	96.1	93.02
Lignite	100	100	100	100
Oil	32.6	42.8	30.3	27.59
Natural Gas	100	100	100	69.30
Hydro	100	99.93	99.96	95.94

* Projected; *Note:* Excludes nuclear and wind power; does not take into account increases in domestic gas production from 2009
Source: Eleventh Five Year Plan, Government of India, 2007

The third factor relates to the lack of infrastructure – including grid connectivity and gas pipeline networks – to facilitate the distribution and substitution of energy sources.

The final factor relates to distortions in pricing. There are two points of distortion; first, prices paid by marketing and distribution companies to exploration companies, and second, prices paid by energy users to marketing and distribution companies. Figures 2a–c below show the pricing of energy in India over time, compared with international benchmarks. Apart from oil,[10] energy has been consistently priced very low, regardless of costs of production and distribution, through adjustments elsewhere, mainly subsidies. The coal sector is under state ownership, and coal has been priced very low at both ends of the chain. Coal prices were partially decontrolled in 2005, and companies permitted to carry out an 'e-auction' of 10 per cent of production to obtain a notional market price, which could then be used as a guideline for pricing the remaining 90 per cent. It is unlikely that this has had much impact in practice. In the gas market, a mix of pricing regimes exists for prices paid to exploration companies, depending on the fiscal regime governing the field. Gas to major end-users has been priced at the 'administered' level shown in Figure 2c below, which has until recently been very much lower than international benchmarks.

In general, a lack of connectedness, based on commercial principles, exists in energy pricing, between the producing and consuming sectors. Hypothetically, if energy were traded at international prices, one would expect an upward movement in prices down the entire chain of energy producing and consuming sectors. In 2010, a series of landmark policy changes occurred in the pricing of energy products. Prices for petroleum products, apart from kerosene and LPG,[11] were deregulated. The 'administered price' of gas was more than doubled, from US$ 1.8 per mmbtu to US$ 4.2 per mmbtu. Additionally, the government announced that subsidies to end-users in the main gas consuming sectors would be borne by the government, and not by state-owned companies.

[10] The price paid to oil producers and refiners is based on international benchmarks, but the price to the end user is subsidised for some petroleum products.
[11] The price of LPG was increased, but not deregulated. The price of diesel was also only partially deregulated, that is, subsidised if crude oil prices increase above a 'ceiling'.

A policy intention is to implement a scheme of direct transfers in 2012 (this is being trialled in parts of India), where subsidies will be paid directly to the eligible end-user in the main consuming sectors. These are important developments, and in the following sections of this paper we set out to analyse the implications for natural gas.

Figure 2: Indian Energy Prices versus International Benchmarks

(US$ per Tonne of Oil Equivalent)

Figure 2a: Oil Prices

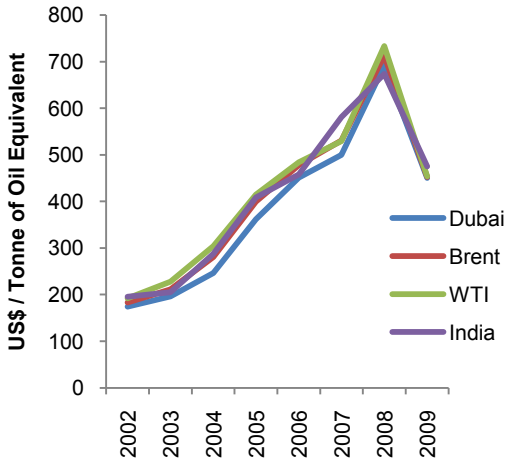


Figure 2b: Coal Prices

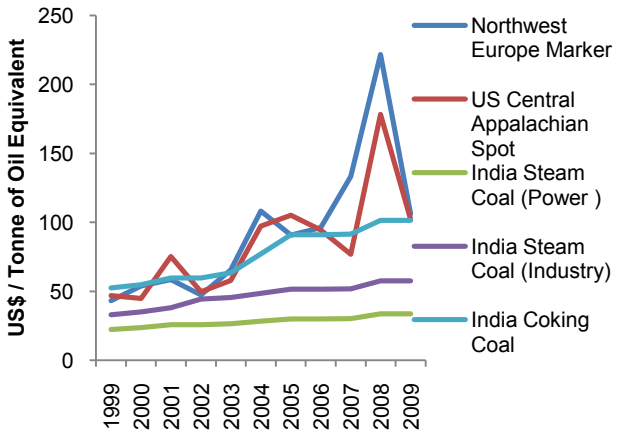
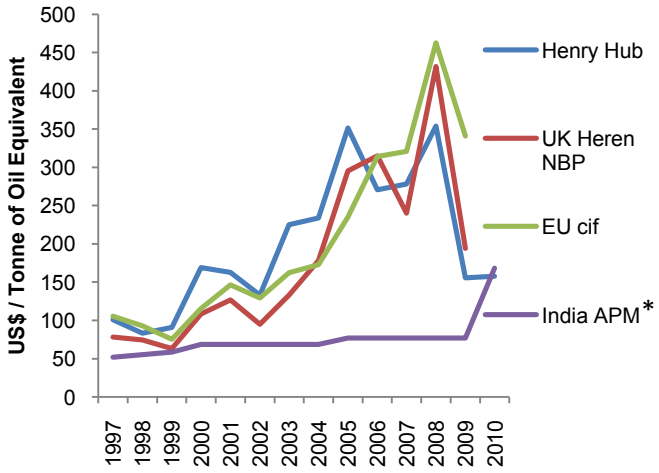


Figure 2c: Natural Gas Prices



Source: Compiled by Authors;
Note: Data on UK Heren NBP and EU cif natural gas prices until 2009 in Fig. 2c.
* APM Administered Price Mechanism

3. Political Economy and the Development of the Hydrocarbons Sector

India is a federal democracy of 1.2 billion people, with 28 states and seven 'union territories', and a constitutional division of power between the centre and states. Elections to the central and state governments are held every five years, often accompanied by changes in political alignments.

At the time of independence in 1947, essential goods and services were provided by small private companies, and were limited to urban areas. In order to extend the benefits of industrialisation to the majority of the population, early governments adopted a centrally-planned resource allocation approach to economic development. Companies were nationalised over the subsequent three decades, and grew into massive, vertically-integrated 'public sector enterprises' in every industry sector. The prices of final goods and services were kept below costs, to promote distributional equity. [12] Over time, the practice of under-pricing final goods resulted in poor revenue for public enterprises.[13]

An important aspect of planned development was the Five Year Plan. It was formulated by the Planning Commission based on consultations with various government ministries. The economy was liberalised in 1991 following a macroeconomic crisis, but the Five Year Plan has continued to play an essential role.

Since 2000, as a multitude of political factions emerged, regional politics began to play a greater role in economic decision making. Despite the improved efficiency and consumer choice brought in by rapid economic growth, there has been a section of the population persistently untouched by its benefits. [14] The policy problem is therefore extremely complex; rapid economic growth necessitates greater flexibility in pricing and allocation mechanisms; yet the existence of a substantial number of people below the poverty line, and the hangover from decades of central planning, present significant challenges.

The hydrocarbons sector is representative of this planned approach to economic development and its pitfalls. Although the primary focus has been on oil, both oil and gas have been subject to similar types of policies. Considerable literature exists on the structure and evolution of the gas sector.[15] Here we provide a brief overview, first of the evolution of the industry structure, and second, of distributional objectives being met through the gas pricing mechanism.

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[12] Primarily for essential commodities which included energy.
[13] Further literature on the evolution of India's economic policy can be found in Ahluwalia (2000), Chakravorty (2003), Kurien (2000), and Tongia (2003).
[14] 30 per cent of the population is below the poverty line, and 70 per cent of the population live in rural areas.
[15] See Joshi and Jung (2008).

In terms of the evolution of industry structure, in the immediate post-independence era there were two major oil and gas exploration companies; Oil and Natural Gas Corporation (ONGC) and Oil India Limited (OIL). ONGC began in the mid 1950s, initially as a Commission linked to the Ministry of Petroleum and Natural Gas, which eventually became a public sector corporation in 1994. OIL began as a private company in 1959, and was nationalised in 1983. Essentially, these were India's National Oil Companies (NOCs). As far as exploration and production is concerned, a competitive fiscal regime did not exist between the post-independence era and liberalisation, and companies simply 'nominated' or expressed interest in fields for oil and gas exploration, and were granted licences to do so by the government.

Historically, oil was the primary focus of policy. However, gas began attracting increased attention after the discovery of the offshore Bombay High fields by ONGC, from which production began in 1974. By 1984, the government recognised the need for a gas distribution network, and set up a separate state-owned company, the Gas Authority of India Limited (GAIL), to develop one. ONGC made another discovery, the western offshore Bassein fields, in 1988. The focus on increasing domestic gas production intensified in the 1990s; this was mainly due to an awareness of the need to encourage fuel substitution, as oil production, which had up to the late 1980s met about half of India's oil use, plateaued around the same time. GAIL set up the first large interregional pipeline, Hazira–Vijaypur–Jagdishpur (HVJ), in the 1990s, which later led to the start of city gas distribution.

Economic liberalisation led to further changes in industry structure. In the 1990s, as part of this, and also as public sector exploration companies failed to make further gas discoveries, the government auctioned off fields that had been 'discovered' but not fully developed by NOCs, to joint ventures between private companies and NOCs under production sharing agreements.[16] An upstream regulator, the Directorate General of Hydrocarbons (DGH), was set up in 1993.

In 1998, the government launched a new regime, the New Exploration Licensing Policy or NELP. This was based on production sharing agreements, pitched at greater private and international participation, and under it, regular rounds of auctions were carried out on the basis of competitive bidding. Under the first eight rounds, 234 contracts were signed. The ninth round was launched in October 2010. However, bidders have predominantly been domestic private sector companies, and not international companies. Along with the domestic exploration under the NELP rounds, India

[16] Also known as the 'discovered fields' policy regime.

began importing LNG in 2004; it should be noted that, particularly in fertilisers, there was a demand for LNG despite high prices, as prices of the competing input, naphtha,[17] were very high.

A midstream and downstream regulator, the Petroleum and Natural Gas Regulatory Board, was established in 2006, after prolonged bureaucratic procedures. In 2008, the private company, Reliance Gas Transportation Infrastructure Limited (RGTIL), entered the pipeline business with the construction of the 1400 km 'East–West' pipeline. The industry structure has thus gone from small private companies, to large public corporations, to a mixed (private and public) structure. Although the NELP regime is the current 'ruling' fiscal regime in oil and gas, fields are governed by the original fiscal regime under which they began operation.

The distributional objective in gas has been pursued mainly through pricing and allocation. Prior to the 1970s, when gas production was low, gas prices were fixed by an expert committee (Joshi and Jung, 2008). Between 1970 and the mid-1980s, prices were negotiated between public companies and large gas users (Joshi and Jung, 2008). In 1987 the distributional objectives became explicit, when the government implemented the Administered Pricing Mechanism (APM),[18] resulting in controlled prices across different consumers. Initially, producers were allowed a specified return on their investment and cost of production, and only gas to consumers in the north-eastern states (officially regarded as underdeveloped) was subsidised. A 'gas pool account' was created in 1992, to compensate ONGC and OIL for selling gas below their costs of production in the north-east (Joshi and Jung, 2008, 91).

When nominated fields were replaced by the 'discovered fields' regime, producer prices to private companies were negotiated through production sharing contracts. Regardless of higher producer prices, users continued to be sold gas by GAIL at the administered price, and the 'loss' was borne by state-owned companies (mainly ONGC). ONGC essentially subsidised the difference between fixed consumer prices and contractually determined higher joint venture gas prices, both to gas users and to GAIL (Joshi and Jung, 2008, 92). As state-owned companies made profits on other revenue streams, the subsidies were not considered 'losses', but 'under-recoveries'.

Between 1997 and 2005, committees were appointed to work out an effective pricing mechanism for gas, and administered prices were increased a few times, notably in 1992, 1997, and 2005 (although they remained well below costs of production). The interlinkages created between producing and consuming sectors (such as power and fertilisers) created a situation where the latter

[17] A liquid fuel, the price of which is based on the price of crude oil.
[18] This is different from the APM for oil, which began as a response to the oil shock of the 1970s, and which was eventually abolished.

had grown accustomed to the provision of these goods to their consumers at very low prices, and were resistant to price increases. As the majority of these sectors' consumers comprised farmers, who also formed the largest proportion of the electorate, governments were reluctant to increase gas prices. Thus, between 2005 and 2010, APM gas prices remained frozen, with state-owned companies and the Federal government taking on the burden of subsidies. A similar situation existed in the oil, or petroleum product, sector. In the oil sector, in an attempt to lessen the negative impact of subsidies on the finances of public sector companies, the government began issuing 'bonds'[19] to them from around 2005, effectively transforming the subsidies into debt, and therefore part of the government deficit. This practice was widely recognised as unsustainable.

The terms of NELP introduced a parallel pricing system into the gas sector – the gas price under NELP was 'discovered' as a notional 'market' price through a procedure outlined in the NELP contractual provisions. The increasing subsidy burden from APM gas may have been one of the factors that led to the 2010 decision to increase APM gas prices to the same level (US$ 4.2 per mmbtu), as part of broader reforms in petroleum product and gas pricing. The deregulation of petroleum product prices in 2010, and the increase in APM gas prices, could result in an improvement of around US$ 1 billion in the revenues of ONGC – with an equivalent worsening of the government budget position.

The price increase in gas is an *administered* increase, and has been carried out only on the upstream side. This removes much of the distortion on the producer side, but in a sense pushes the focus of the problem further into the consuming sectors, where parallel reforms have not taken place at the same speed or in the same manner, and upon which there is now increased pressure to act. The focus has also been pushed onto plans for direct subsidies to be provided by the government. The price increase improves transparency and reduces the distorting effects of low input prices, but it is unlikely to be the end of the story.

We delve into questions of pricing in Section 6, where we look at proposals for reform in the power and fertiliser sectors, and at specific attempts in fertilisers to link pricing with the price of NELP gas. Essentially, despite the price increase, there may be a 'demand' for gas at a price higher than US$ 4.2 per mmbtu, which can be realised through greater fuel substitution in sectors such as fertilisers, where competing inputs, such as naphtha, are more expensive. We proceed to explore this argument further, later in this paper.

[19] Commonly known as 'oil bonds'.

4. Supply and Demand

Official forecasts of gas supply and demand have been carried out mainly for the short term: much of this forecasting has been for the five year plans. Put simply, the conventional process of central planning begins with a quantity based, for example, on likely domestic production. This quantity is then allocated amongst different uses, and then 'priced' by planners. In the event of a shortage, the price is unlikely to be revised, but the quantity may be increased in other ways, for example though imports. Planned forecasts are therefore based on key assumptions about availability; in the official supply forecasts, it is assumed that forecast supply will be utilised. Similarly, in official demand forecasts, it is assumed that prices will be set at levels that allow gas to compete with alternative fuels, and that the infrastructure networks necessary for delivery will exist.

In contrast, a more market-oriented approach requires that the fiscal terms of exploration contracts are set to ensure that potential supply is brought into production, and that the price signals accurately reflect market conditions. Therefore, limited conclusions can be drawn about the potential for gas in a reforming sector, based on forecasts conducted for a centrally-planned sector.

Official forecasts appear to reflect aspects of this thinking in their reporting of demand and supply. First, 'demand' refers to the 'use' of gas, rather than depicting a position brought about through the price system. And second, supply and demand are sometimes reported as one number (for example, in the India Hydrocarbon Vision 2025 forecast). The distinction between the two is often blurred in the assessment methods used, particularly for LNG, where agencies may have used 'demand' assessments to estimate LNG supply as a residual, regardless of actual re-gasification capacity. In this section we review these forecasts, in an attempt to demonstrate the thinking behind them. The order of analysis is: domestic supply; domestic demand, and the need for imports (LNG and transnational pipelines).

4.1 Domestic Supply

India has 26 sedimentary basins; only 20 per cent of this sedimentary area has been well-explored, and 14 per cent is completely unexplored (Directorate General of Hydrocarbons, 2007). Most of the explored basins are gas prolific. Of the total proved reserves of 1,881 mtoe, 58 per cent comprise gas;[20] out of twenty-one blocks of discoveries, nine comprise oil, while the rest comprise gas or both oil and gas. Policy on gas has largely been *reactive* and fragmented rather than *proactive*, as policymakers did not recognise its growing potential early on.

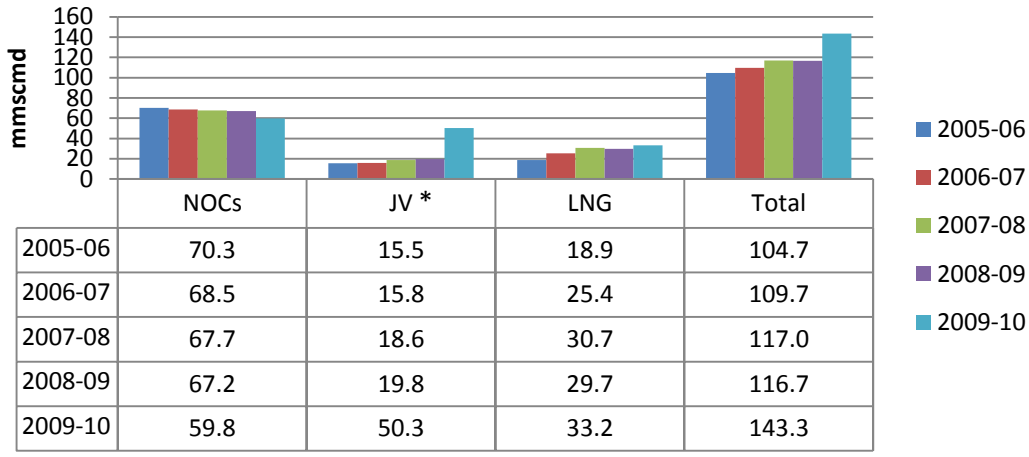
[20] India had proved reserves of 5.8 billion barrels of crude and 1,120 bcm of natural gas at the end of 2009 (BP Statistical Review of World Energy, June 2010).

India has had three fiscal regimes for oil and gas exploration. The 'nominated fields' regime was the earliest, where NOCs could formally express interest in an exploration block, which was then awarded to them on a royalty-based scheme, without profit sharing or the option of divesting their participating share. This regime was stopped in the late 1990s. The 'discovered fields' regime began after liberalisation in the 1990s. Under this, private companies could form joint ventures with NOCs, and bid for former nominated fields that were being auctioned. Private companies were also paid a 'market price' (or a price higher than APM) by the government. NOCs were theoretically permitted to divest their participating shares, although thus far no NOCs have divested their share of discovered fields. Licences for nominated fields will expire in 2012, after which they will revert to the government for possible re-auctioning.

NELP was launched in 1998 to increase domestic and international private investment in oil and gas. Eight rounds of auctioning have led to contracts covering 48 per cent of India's sedimentary basins, yielding discoveries of more than 600 MMT of oil and oil equivalent gas. The government aims to achieve full coverage of the remaining area by 2014. NELP IX, launched in October 2010, is the last round under NELP, after which an Open Acreage Licensing System is likely to be introduced.

For gas, Figure 3 shows declining NOC production, and increasing production from joint ventures and private companies (under NELP). Total supply in 2009 was approximately 52 bcm (143 mmscmd) of which 23 per cent was from LNG imports.[21]

Figure 3: Gas Production by Producer Category (in mmscmd)



	NOCs	JV *	LNG	Total
2005-06	70.3	15.5	18.9	104.7
2006-07	68.5	15.8	25.4	109.7
2007-08	67.7	18.6	30.7	117.0
2008-09	67.2	19.8	29.7	116.7
2009-10	59.8	50.3	33.2	143.3

Source: Petroleum Planning and Analysis Cell, Ministry of Petroleum, Government of India
Note: Figures may be subject to small variations.
* JV – Joint Ventures and Private Companies

[21] Petroleum Planning and Analysis Cell; Online at www.ppac.org.in/GAS/H-Import.htm and www.ppac.org.in/GAS/H-Production.htm

The most prolific gas discovery under NELP has been in the D-6 block of the Krishna Godavari (KG) basin, operated by Reliance Industries Limited (RIL), which has a total of nineteen discoveries and proven reserves of over 10 tcf. There are two 'development plans' in operation, one for the 'MA-26' discovery and the second for the 'D-1' and D-3' discoveries. These three have collectively produced 60 mmscmd, and have a potential peak production of 80 mmscmd. Another RIL block, 'NEC-OSN-97/2', is, at the time of writing, soon expected to add further to supply. Other NELP discoveries in the eastern offshore basin include those by ONGC ('KG-DWN-98/2') and by Gujarat State Petroleum Corporation ('KG-OSN-2001/3').

Due to a lack of transparency, inadequate information exists on the size of discoveries and on the quantity of gas that could eventually be brought to market. Policymakers have tended to be very optimistic in their assessments of the range of possible supply options; in reality, there are obstacles to exercising these options, as we discuss later.

The existing supply forecasts are for the short term (2012), and are not very numerous. There are two main official forecasts, both carried out for the Eleventh Five Year Plan, from 2007 to 2012, with, it may be argued, a planner's outlook.

Table 4: Domestic Supply in 2012 (in mmscmd)

		Supply Forecast
Ministry of Petroleum[22]	*'Normal'*	108
	'Optimistic'	202
Planning Commission[23]		173
Most Likely Estimate		150

Source: Compiled by authors

The Ministry of Petroleum published two forecasts; both are based on an assumed decline of NOC production and an increase in private production. The 'optimistic' forecast envisages large additions from private production, not just from the KG D-6[24] fields, but also an almost equivalent amount (54 mmscmd) from blocks owned by the Gujarat State Petroleum Corporation (GSPC). The Planning Commission based its forecast on an average of the two forecasts.[25] The operations of exploration companies have, however, been affected by the economic downturn, and GSPC

[22] *Report of the Working Group on Petroleum and Natural Gas for the Eleventh Plan*, Government of India, 2006, Table 8.12, 67.
[23] *Volume III, Eleventh Five Year Plan, 2007–2012*, Government of India, 2007
Table 10.20, 368
[24] Additions of 20, 30, and 40 mmscmd in 2009, 2010, and 2011.
[25] It is unclear how this average was computed.

production by 2012 will be much lower (around 6 mmscmd). The most likely supply estimate is therefore approximately 150 mmscmd.

Regardless of the thinking behind forecasts, one obvious feature is that forecast supply will depend very much on the success of NELP. Table 5 shows the progress made *after* the signing of contracts, for fields auctioned in rounds I to V.

Table 5: Status of Discoveries under NELP (1 April 2009)

NELP Round	Blocks Awarded	Blocks with Discoveries	Nature of Discoveries			Discoveries Under Production	Development Plan yet to be made	Development Plan under consideration
			Oil	Gas	Both			
I	24	6	2	37	2	3	26	12
II	23	5	2	4	2	3	4	1
III	23	4	1	6	3	-	9	1
IV	20	4	7	1	-	-	8	-
V	20	2	1	2	-	-	3	-
Totals	110	21	13	50	7	6	50	14

Source: Directorate General of Hydrocarbons

Although initial rounds of NELP led to a substantial number of contracts, few have reached the production stage. NELP VIII resulted in a small number of contracts, the majority of which were with NOCs. There has also been no participation from international oil companies. This indicates a serious failure as compared with policy intentions and expectations, This failure needs to be addressed both by reviewing the fiscal terms of NELP, and in the design of the next exploration regime which will replace NELP. (As noted, the current NELP IX is the last under the existing system).

4.2 Domestic Demand

Demand forecasts are subject to the same limitations outlined earlier in this section. They are also limited by the use of different methodologies. Table 6 below summarises the main official forecasts.

The India Hydrocarbons Vision (IHV) 2025 is an 'optimistic' forecast from 1997. It reports one number for supply and demand, reflecting the thinking discussed earlier. Interestingly, it also assumes a liberalised gas sector operating at market prices, large additions to supply between 2001 and 2010, and LNG imports of 15 MMTPA (or 55 mmscmd) by 2007. In reality only half of this has occurred, and domestic production began increasing only in 2009. The forecast of the Expert Committee on Integrated Energy Policy (IEP), on the other hand, is from 2006, and is somewhat conservative, as actual supply in 2009 was 34 per cent more than forecast supply. It assumes GDP growth of 8 per cent, 7 per cent growth in industry sectors, and a falling energy elasticity of GDP growth (from the continued expansion of services relative to agriculture and manufacturing).

The forecasts from the Ministry of Petroleum and Natural Gas are short-term (2012), and take a 'middle' position compared to the other two. The method used is 'bottom-up' rather than 'top-down', by adding projected demand across different sectors, using assumptions on growth rates, input prices and requirements, manufacturing capacity, and technology. Demand at the beginning of 2012 is highlighted in Table 6.

Table 6: Demand Forecasts for Gas in India (in mmscmd)

	Ministry of Petroleum and Natural Gas (2006)[26]	Integrated Energy Policy Report (2006)[27]	India Hydrocarbon Vision 2025 (1997)[28]
2001–02			151
2006–07		87	231
2007–08	171.2		
2008–09	196.7		
2009–10	225.5		
2010–11	262.1		
2011–12	279.4	134	313
2016–17		194	
2021–22		295	
2024–25			391
2026–27		411	

Source: Given in Table.

Demand depends crucially on the main consuming sectors. The shares of consuming sectors at the beginning of the Eleventh Five Year Plan (2007) were; power (40 per cent), fertilisers (29 per cent), petrochemicals (9 per cent), city gas (4 per cent), the consumption of LPG and other liquid hydrocarbons (4 per cent), and other sectors (14 per cent).

4.2.1 Sector Demand

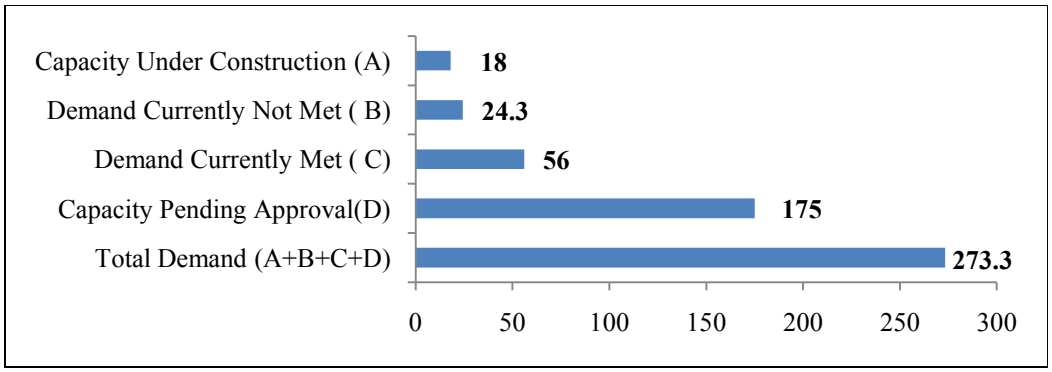
There are two potential areas of gas demand in the **power sector**; grid-connected, gas-fired power generation, and captive generation. In both of these, the price competitiveness of gas compared to competing fuels will determine future demand. In grid-connected power, gas has to compete with coal. Official forecasts assume price competitiveness without fully elaborating on the assumptions, and we investigate these further in Section 6. Power supply needs to grow by 31 per cent (overall) and 40 per cent (peak) between 2008 and 2012, to support GDP growth rates of between 9 and 11 per cent (Central Electricity Authority, 2007: Seventeenth Electric Power Survey of India.).

[26] *Report of the Working Group on Petroleum and Natural Gas for the Eleventh Five Year Plan*, Government of India, 2006, Table 8.11, 66.
[27] *Report of the Expert Committee on Integrated Energy Policy*, Planning Commission, Government of India, 2006, Table 2.12, 28.
[28] *India Hydrocarbons Vision 2025*, Ministry of Petroleum, Government of India, 2006.Annex IV.

In 2009, there was 16,385 MW of gas-based capacity which required 76 mmscmd of gas, of which 33 per cent was unmet. Official short-term forecasts of demand for gas in power are in Figure 4 below. Capacity under construction is planned for completion by 2012 and this, together with existing capacity, is expected to lead to 84 mmscmd of demand by 2012. The remainder of demand to 2015 includes 35,000 MW of capacity pending approval, to be developed by 2015.[29]

Captive generation[30] was deregulated in 2003, as part of extensive power reforms. The introduction of third party access to the transmission grid allows consumers to use the grid to sell electricity to third parties, subject to a 'cross-subsidy surcharge', or a fee paid by the seller to the state utility to compensate the latter for its potential loss of revenue, from which subsidies to poorer consumers are financed. In practice, as states are free to set the surcharge, its precise level is subject to debate.

Figure 4: Composition of Gas Demand for Power (2014–15) in mmscmd



Source: Compiled from published sources

Accurate assessments of captives have been difficult. The most frequently used official estimates are from the Central Electricity Authority. Of installed captive capacity in 2007, coal comprised 51 per cent, diesel 35 per cent, and gas 13 per cent. The average captive Plant Load Factor is around 42 per cent (Infraline, 2010).

Table 7: Total and Gas-based Captive Capacity

	Installed Capacity	
	Total (MW)	**Gas-Based (%)**
2003–04	18,740	14.65
2004–05	19,102	15.01
2005–06	21,468	14.09
2006–07	22,335	13.32

Source: *TERI Energy Data Directory and Yearbook*, TERI Press, 2009; *All Indian Statistics: General Review,* Central Electricity Authority, Government of India, 2008.

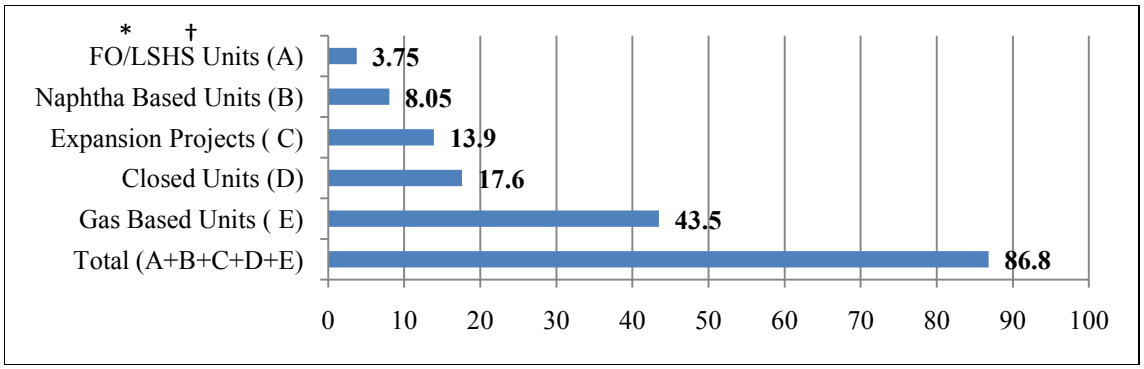
[29] Union Power Secretary, Government of India. See www.indiaenews.com/business/20090910/220088.htm
[30] The setting up of independent power plants, typically by large consumers, to generate electricity for their own consumption.

Since the capacity deficit developed in mid-2000, grid-connected users have been subject to frequent system interruptions. This has led to an increased demand for captive power at higher prices but better quality. The Ministry of Power estimates that 10,000 MW of captive capacity will be added by 2012. The competing fuel to gas in captives is diesel, which is partially deregulated; it is subsidised if oil prices breach a threshold (this was recently US$ 83 a barrel, but is periodically revised). However, reforms combined with the chronic power deficit, appear to have boosted the captive power sector.

The demand for captive and merchant power has emerged as a result of system failures elsewhere. In particular, the failure of several large power generation projects in the mid-1990s, due to contractual disputes, and the absence of alternative plans, meant that planned capacity additions to meet growing demand did not take place. The resulting power deficits in the 2000s and the deregulation of captive generation in the 2003 Electricity Act (Government of India, 2003), led to increased demand for captive power, mainly from the industrial consumer sector. As gas at higher prices appears to be acceptable in captives, and as captive users are mainly industries that require continuous electricity supply, there is no real justification to subsidise diesel for use by non-agricultural users. The system of subsidising all inputs, so that costs of products are kept low specifically for a particular segment of consumers (such as farmers), is inefficient.

In **fertilisers**, which are entirely in the public sector, gas use is driven by the economics of inputs (domestic versus imported feedstock), and the production process for *urea* (the main fertiliser product). The main alternative inputs for urea are naphtha and gas.

Figure 5: Demand for Gas in Urea, 2012 (mmscmd)



Source: Department of Fertilisers
Note: * FO – Fuel Oil; † LSHS – Low Sulphur Heavy Stock (residual fuel processed from indigenous crude)

The Department of Fertilisers estimated that the demand for urea will grow by 140 per cent between 2006 and 2012. This will require larger quantities of gas, due to conversions to gas of all naphtha-

based manufacturing plants by 2012, the revival of previously closed units, and new capacity, all as part of an Investment Policy announced in 2008, with the aim of achieving self-sufficiency in urea manufacturing.

The growth of **city gas** depends on the extension of the distribution network, from 10 cities in 2007 to 40 by 2014. By 2010, there were 22 city gas distribution networks. If network expansion to the additional 30 cities between 2007 and 2014 occurs at a relatively constant rate, it implies that GAIL is (marginally) behind schedule.

The Eleventh Five Year Plan contains forecasts for gas use by sector; these are in Table 8 below. Limitations in the methods used make it difficult to draw robust conclusions. Actual consumption by sector in 2009 was lower than forecast demand.

Table 8: Demand for Gas by Consumer Sector – Eleventh Five Year Plan (in mmscmd)

Sector	2007–08	2008–09	2009–10	2010–11	2011–12
Power	79.7	91.2	102.7	114.2	89.0
Fertilizers	41.0	42.9	55.9	76.3	86.8
City Gas	12.1	12.9	13.8	14.8	15.8
Industrial	15.0	16.1	17.2	18.4	19.7
Petrochemicals& Refineries	25.4	27.2	29.1	31.1	33.3
Sponge iron & Steel	6.0	6.4	6.9	7.4	7.9
Total	179.2	196.6	225.6	262.2	252.5

Source: *Report of Working Group on Petroleum and Natural Gas for the Eleventh Five Year Plan*, Government of India, 2006, Table 8.11, 66.
Note: 2012 numbers for power and fertilisers are from sector estimates earlier in this section

4.3 Need for Imports

The forecasts of total domestic demand for gas (with the exception of the conservative IEP estimate), when compared with likely domestic supply of 150 mmscmd, indicate a supply shortfall of at least 100 mmscmd in the short term. Policymakers have pursued two options for meeting shortfalls in gas; LNG imports and transnational pipelines.

LNG imports depend on the expansion and addition of re-gasification capacity. The table below shows official forecasts for LNG supply, and the 'likely' forecast based on the speed of capacity addition. According to official forecasts, it is therefore clear that there will be a deficit in gas availability even *after* LNG imports. Although LNG imports began in 2004, prior to the start of gas production from the eastern offshore fields, LNG remains very relevant to the western part of India, as four of the five major existing and planned terminals are located on the west coast.

Table 9: LNG Supply Forecasts, 2012

	LNG Supply (MMTPA)	LNG Supply (mmscmd)	Total Supply (mmscmd)
Ministry of Petroleum	23.75	83	191
Planning Commission	23.75	83	256
'Likely' Estimate	18.00	67	217

Source: *Volume III, Eleventh Five Year Plan*, 2007, Table 10.21, 369; *Working Group on Petroleum and Natural Gas*, 2006 Table 8.13, 68.

The table below shows contracted LNG supply (apart from the east coast Mangalore terminal) for 2012.

Table 10: LNG Supply by Terminal, 2012

Terminal	LNG Supply in 2012	
Dahej (Petronet LNG Ltd)	12.5	Under Expansion
Hazira (Shell)	2.5	Under Expansion
Dabhol (NTPC* and GAIL)	5.0	Under Expansion
Kochi (Petronet LNG Ltd)	1.5	Planned
Mangalore (ONGC)	-	Planned

Source: Petronet LNG Limited; Govt. of India;
*NTPC: National Thermal Power Corporation

There is likely to be 20 MMTPA (or 74 mmscmd) of LNG capacity by 2012. The shortfall in overall supply will still be around 50 mmscmd (or 18 bcm).

LNG contracts in India are a mix of long term, short term and spot contracts, of which short-term and spot comprise 45 per cent. LNG is, effectively, the swing supplier of gas. Essentially, the supply of gas could be raised, effectively without limit, via LNG imports at world prices. However, a potential bottleneck is re-gasification capacity, and further investment may be required here.

The second, longer-term import option is gas through **transnational pipelines**. Geographically, India could receive imports of gas through countries such as Myanmar, Bangladesh, and Iran, and through Central Asia. There are two main geopolitical factors; first, the feasibility of laying gas pipelines to the north-west though politically unfriendly territory – such as Afghanistan and Pakistan – and second, the ability to compete with growing energy demand from countries such as China for pipeline gas from the east. The Iran–Pakistan–India pipeline (40 mmscmd) has consistently run into obstacles and remains unresolved. India lost out to China on the potential Myanmar–Bangladesh–India pipeline. After a decade of negotiations on the Turkmenistan–Afghanistan–Pakistan–India pipeline, a breakthrough in diplomacy occurred in December 2010. Construction will begin in 2012 and end in 2015, for 38 mmscmd of gas to India. Unofficial reports put the landed price of gas for India at nearly US$ 10 per mmbtu. Given the history of pipeline

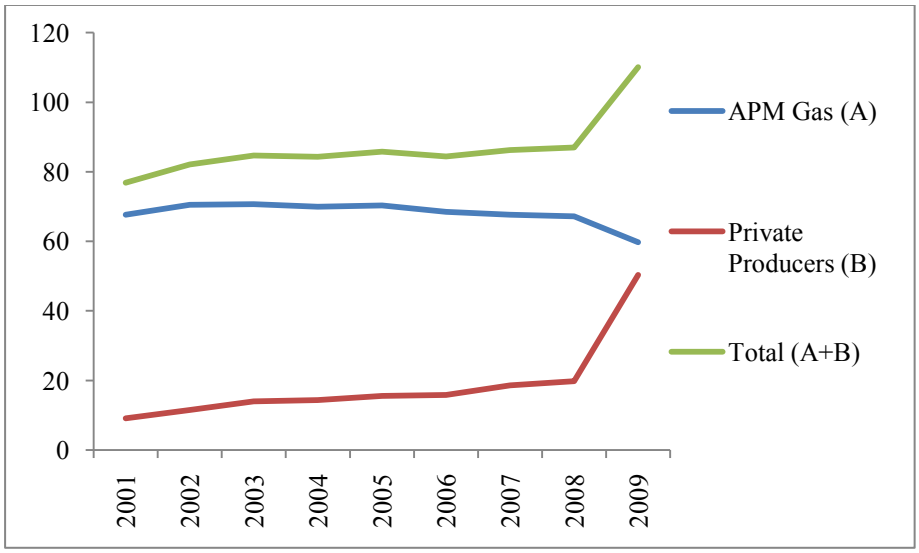
negotiations, these developments remain tentative, and transnational pipelines remain, on the whole, an uncertain supply source.

4.4 Supply and Demand: Summary of Analysis

There are no robust, long-term macro level forecasts of supply for a reforming or liberalised gas sector, and existing forecasts have mainly been carried assuming a continuation of the present system. Existing forecasts however, generally point to a substantial deficit in short-term supply. Supply forecasts also indicate rapid growth in domestic supply from private companies. If we consider past and existing production levels, it is clear that APM gas, which comprised 75 per cent of domestic gas in 2007, is declining, whilst gas from private producers is likely to overtake APM gas production. Figure 6 shows the net production of gas[31] under the APM regime, under private production, and in total, between 2001 and 2009.

The process of forecasting generally reflects the difficulties encountered in the transition from a planned to a market oriented sector. It is necessary to look more closely at the general assumptions upon which these forecasts may be based, in order to assess the future potential for gas. Clearly, this depends on the fiscal terms and the price. Thus, future supplies of domestic gas depend crucially on the success of NELP (and of future fiscal regimes).

Figure 6: (Net) Production of Gas in India by Producer Category, 2001–09 (in mmscmd)



Source: Compiled with data from the Petroleum Planning and Analysis Cell, Ministry of Petroleum

There are two areas of concern with regard to this. First, NELP has, so far, failed to attract any interest from international exploration companies. And second, as seen in Table 5, many blocks that

[31] After deducting the quantity flared.

were auctioned under NELP have yet to be properly explored. Our analysis suggests that there are two broad policy areas which require attention in order to address these issues.

The first relates to fiscal terms. In previous NELP rounds, Indian NOCs have bid aggressively by offering larger profit shares than private companies, and have consequently won more exploration blocks. Private companies were awarded 16 blocks against 36 to NOCs under NELP VI, and 22 blocks against 23 awarded to NOCs in NELP VII.[32] Most blocks won by NOCs have gone to ONGC, which already has large nominated acreages, and is overburdened with exploratory commitments. In the bidding rounds for NELP VI and VII, private companies lost out on five and eight blocks respectively, based purely on profit-sharing criteria. Another concern relates to tax provisions; companies based in India are permitted to offset their losses in gas exploration against other businesses. This may incentivise them to commit to sometimes unrealistic work programmes whilst submitting their bids, which places non-Indian companies at a disadvantage. This brings us into a wider argument on efficiency, the need for a level playing field, and the original objectives of the NELP fiscal regime.[33]

These aspects could be addressed through a flexible acreage exploration policy. One option is to permit companies the limited exploration of a chosen area within a time period, without commitments on final exploratory inputs or profit sharing terms, but with preferential rights in the final award of the acreage, subject to conditions. This may encourage bidders to make realistic offers with respect to profit shares. Another option, which is likely to be adopted after NELP IX, is an Open Acreage Licensing Policy, allowing companies to study geological data and bid for blocks on a rolling basis.

The second area relates to the enforcement of technical provisions in exploration programmes. Of the 70 discoveries under NELP, 41 have taken place in blocks from the first round. The number of blocks with discoveries is only around 20 per cent of the total awarded. Although there were originally no provisions for extending the maximum exploration period, in 2006 the government relaxed this constraint, permitting extensions of up to three years. Of the 70 discoveries made under NELP up to 31 March 2009, six have been brought under production. Of the remaining 64, 'development plans' are under preparation for 14, and for the remaining 50 discoveries, there is no clarity on the size or volumes of potential supplies, and around half have not even been declared

[32] According to the Bid Evaluation Criteria for the award of blocks under NELP, bidders were evaluated separately on work programme and profit share parameters. The NOCs have been bidding aggressively on both these parameters, but more on profit share to the government.

[33] That is, whether it is aimed at creating competition in the supplier base and encouraging exploration.

‘commercial’. Therefore, the requirement under NELP that acreages should be released if they are not developed, or not developed fast enough, needs to be tightened up.

The picture thus far shows that the current system (upstream or supply, and downstream, or demand) has been kept in ‘balance’ by the planning process, but with the result that a number of distortions have been created in other sectors.

The main conclusion that can be drawn from existing forecasts is that there is great uncertainty regarding future potential supply which, if left unaddressed, could go either way. The NELP regime was meant to resolve some of this uncertainty on the supply side but, for the reasons discussed earlier, has not fully achieved its objective. Similarly, it is difficult to assess the level of future demand, as gas has long been distributed through a complex system of allocation and pricing. The future potential for gas will therefore depend upon the ability of policymakers to resolve distortions on both the supply and demand sides. This means that events will have to ‘play out’ within the supply and demand sides of the debate before it is possible to make any conclusive assessments.

On supply, as discussed, the challenge is to ensure that the pricing and fiscal regime is designed in an optimal manner. On the demand side, it depends on two crucial aspects of policy: the system of allocation that in a sense underpins the ‘balance’ that currently exists, and the system of pricing and subsidies. The next section investigates the underlying reasons behind this system of ‘balance’ maintained through distortions, as it developed, via the gas utilisation policy. It can be seen as having its roots in the quantitative planning system (with an emphasis on quotas and of subsidies for basic goods via artificially low feedstock prices).

5. Gas Utilisation Policy

'Gas utilisation policy' refers to a system of prioritised allocation which has long influenced planning and operations in the main gas consuming sectors, particularly power and fertilisers. Its origins stem from distributional objectives, and its functions included (a) to 'manage' shortages in gas availability (b) provide gas at subsidised prices to the consuming sectors, and (c) to play an integral part in the planning process. Gas utilisation policy has shaped, and equally may have been shaped by, the operations of consuming sectors. Gas utilisation policy has continued to operate alongside the transition to a market-oriented economy, and its role in this context has been widely debated. One might argue that this is not unique to India, but is a problem of transition faced by every economy at some stage, and the outcome depends on how governments deal with reconciling the economic transition with ideological and political factors. In India, this has been done through policies that aim to fulfil both reform and distributional objectives, often with contradictory effects. This section brings out these contradictory effects through an analysis of one of the most complex policy areas in the Indian gas market.

5.1 The Origins of Gas Allocation in India

As discussed earlier, the exploration and production of gas in India has been carried out by NOCs and private companies; gas was then distributed by the Federal government to major consuming sectors, which lay entirely in the public sector. As the majority of gas was produced by NOCs, and the prices for all consuming sectors were controlled at very low levels from the mid-1980s onwards, there were competing demands for its use and, by the 1990s, there was a shortfall in the quantity available. In the absence of a market mechanism, policymakers decided to introduce an institutional arrangement to enable the allocation of gas and to 'manage' the supply deficit. This led to the formation of a Gas Linkage Committee in 1991.

At that time, 'Gas Utilisation Policy' referred to a regular exercise whereby the government purchased the entire quantity of gas (the majority of which was produced by NOCs) and sold it at subsidised rates to users on the basis of sectoral allocations arrived at by the Gas Linkage Committee. The order of priority fixed was: fertilisers, power, and petrochemicals. There were also elements of *regional* allocation. Some cities, such as Delhi, were prioritised for gas allocation, as part of anti-pollution initiatives; similarly, others were given allocations for 'city gas projects'. In the absence of a formal policy on gas utilisation, the Committee arrived at these decisions on an ad hoc basis. These were implemented entirely in the public sector, and therefore faced few obstacles.

A major portion of APM gas was allocated to the power and fertiliser sectors, for which the price of gas was a 'pass through' cost. This implied that low-priced inputs (gas) contributed to keeping the prices of the final outputs (power and urea) low. The government was therefore effectively subsidising the prices of both the inputs and outputs. The input subsidies, in particular, have created distortions in fuel choice.

The Gas Linkage Committee lost much of its relevance after NELP was launched in 1999, as it did not have oversight on gas produced by private companies. APM gas production also began decreasing. LNG emerged as an important potential supply source, with the formation of Petronet LNG Limited, a new venture promoted by the public sector (but registered as a private company), to procure LNG through spot purchases and term contracts.

Table 11 shows the actual consumption of gas by main consuming sectors, *before* the start of production from the KG-D6 block in 2009.

Table 11: Gas Consumption by Sector, 2008 (in mmscmd)

Sector	APM Gas	Other sources	Total
Fertilisers	16	15	31
Power	25	13	38
Others	14.3	12.9	27.2
Total	**55.3**	**40.9**	**96.2**

Source: Various reports

The objective of gas allocation, which was to better manage the gap between demand and supply, was defeated when the Gas Linkage Committee was forced to allocate more gas (150 mmscmd) than was actually available in 2008. The system was obviously leading to a major policy problem; based on the allocation mechanism, major investments were made in what became idle capacity in gas-fired generation plants, which eventually had to operate at inefficiently low Plant Load Factors. Whilst the role of the Gas Linkage Committee gradually became redundant following NELP, acreages that had been awarded under the older, administered fiscal regime continued to be governed by its allocation policy, leading to a situation where different acreages were governed by different fiscal and administrative regimes.

The move to NELP marked a stage of transition; whilst one objective of the government was to launch a regime aimed at promoting the internationalisation of India's gas supplier base, it was also reluctant to surrender control over the allocation of gas in the process, particularly as the main consuming sectors continued to be dominated by state-owned companies which served the largest sections of the population. The origins of post-NELP gas utilisation policy lie in this period of transition. Over a period of time starting with the first round of NELP, policymakers worked both

these conflicting objectives, through a series of amendments, into the terms of the NELP Model Production Sharing Contract. This is discussed below.

5.2 The NELP Production Sharing Contract

To ensure the successful launch of the New Exploration Licensing Policy, it was necessary to reassure potential investors of the return on their investments, and NELP was presented as a fiscal regime based on market principles and without direct government interference. This regime is governed by the NELP Production Sharing Contract, which contains 37 'Articles' detailing its terms. The Contract applies both to oil and natural gas; however, the terms applicable to gas are less flexible than those for oil. The terms for oil do not include an administered allocation policy. NELP also assures oil producers of international prices.[34] The only restriction is that all crude oil must be sold within India until the economy achieves self-sufficiency in production (this applies to gas as well). NELP incorporates the concept of 'arm's length' decisions, to reassure the producer that the government, a signatory to the contract, will keep its distance from decisions on pricing and sales.[35] While NELP provisions for oil have been consistent, those for gas have been changeable on issues including sales and pricing. Article 21 of the NELP Production Sharing Contract pertains specifically to the contractual terms for natural gas.

Prior to the launch of NELP, Indian policymakers also announced their intention to gradually align the price of gas with that of Fuel Oil,[36] signalling a move towards market orientation. To further reassure exploration companies, policymakers included a clause in Article 21.3 of the NELP Contract, which stated that a contractor would have 'the freedom to market the gas and sell its entitlement' within India. Prior to NELP, private exploration companies operating under production sharing contracts had little independence, as the government either bought the gas based on a fixed formula or, in a few cases, allowed it to be exported.[37]

In the post-liberalisation economic climate of the early 1990s, the inclusion of any formal gas allocation provisions in NELP would have sent mixed messages to private investors. The government, however, appeared to want to retain some form of control through a gas utilisation policy, as gas continued to have competing demands on its use by state-owned enterprises in power

[34] This refers to an import parity price; Article 19.2, pp. 53, NELP Model Production Sharing Contract. Can be viewed online at http://petroleum.nic.in/nelp3.pdf.
[35] 'Accounting Procedure', Clause 1.8, pp. 94, NELP Model Production Sharing Contract.
[36] On 18 September 1997, the Ministry of Petroleum raised gas prices and declared an intention to gradually achieve 100 per cent price parity with Fuel Oil (Volume 2, paragraph 5.77, Ninth Five Year Plan, 1997). Online at http://planningcommission.nic.in/plans/planrel/fiveyr/9th/vol2/v2c5.htm
[37] An example can be found in Article 21.6 of the 'RJ/ON-90/1' Contract, a pre-NELP exploration contract.

and fertilisers. In order to reconcile these conflicting aims, the government included a general reference to a gas utilisation policy in the NELP Model Production Sharing Contract,[38] but did not issue any *formal* statement on its right to prioritise allocation. In the absence of a formal clarification, there were differences in perception between the government and private companies on the extent of 'freedom' guaranteed under NELP.[39] Eventually, in 2007, faced with calls for clarity, in the seventh round of NELP the government clarified its authority to prioritise the allocation of gas through an amendment to Article 21 in the Model Production Sharing Contract for NELP VII.[40]

The NELP Production Sharing Contract from the seventh round onwards therefore has two conflicting objectives; *(1) the assurance of marketing freedom to contractors for the exploration and production of domestic gas,* and (*2) the prioritised allocation of gas to be carried out through the government's gas utilisation policy*. These new provisions did not apply to earlier contracts, with the important exception of KG-D6 gas, although the government later extended these objectives to earlier contracts by announcing a gas utilisation policy with retrospective effect. This formal clarification immediately infringed the marketing freedom of contractors. Policymakers subsequently adopted a range of policy provisions relating to the marketing and sale of gas, in order to reconcile these two conflicting objectives and maintain the validity of the NELP Production Sharing Contract, and of gas allocation. These provisions included the introduction of the 'price discovery' mechanism, uniform prices across consuming sectors, and provisions to distinguish between the 'price' and the 'value' of gas. We examine these in detail later in this section. Much of the distortion in the gas sector has been shaped by this conceptual conflict.

5.3 The Revival of Gas Allocation under NELP

Although NELP contained general references to a gas utilisation policy, for the first 10 years of the regime (1997–2007) these remained unclear and unenforced. This led to a few cases where producers sought government 'approvals' for determining the 'value' (or the valuation) of gas

[38] Article 21, NELP Model Production Sharing Contract, rounds I to VI. An example of such a reference can be found in Article 21.1, which contains the phrase 'in the context of the Government's Policy for the utilisation of Natural Gas', without detailing what this policy might be. This is typical of NELP contracts for rounds I to VI.

[39] It is unclear why this issue was not addressed in Rounds I to VI; one possibility is that the earliest gas finds under NELP were made around 2006, and gas production from these was scheduled to begin only in 2009.

[40] Article 21.3 was amended to read 'the Contractor shall have freedom to market the gas and sell its entitlement as per Government Policy for utilisation of gas among different sectors.' A new clause, Article 21.3.1, was also inserted, which read 'For the purpose of Article 21, the Government may from time to time frame policy for utilisation of gas among different sectors, both for Associated Natural Gas as well as Non-Associated Natural Gas, which would cover issues relating to gas supplies to different consumer sectors.'

(discussed in later sections), on the assumption that they had the freedom to market their gas.[41] In 2006, Reliance Industries Limited (RIL) sought government approval for the valuation of its gas, to be sold from its NELP 'D-6' block to Reliance Natural Resources Ltd (RNRL) for consumption by a greenfield power utility. At the time, the government rejected the valuation, but did not object to the company's marketing plans for supplying nearly half of the first stage of the block's production to a greenfield utility.[42] RIL sought approval of its valuation again in 2007; once again it did not seek any approvals for its marketing strategy, although it planned to sell the entire first tranche of its production to users in the fertiliser and power sectors. Following this second application, the government began a general review of gas supply and pricing. A Committee was appointed to make recommendations on the issue. This supported government intervention through a formal gas utilization policy; it also recommended that the policy be extended to include past and existing Production Sharing Contracts under NELP.

The debate over gas allocation eventually resulted in the formation of an Empowered Group of Ministers (EGoM), which approved the valuation and price of D-6 gas. The EGoM continues to provide an interface between gas producing and consuming ministries. It meets frequently, and its decisions on gas utilisation have continued to hold validity, although no formal policy has yet been announced. The reference to 'Gas Utilisation Policy' in the rest of this paper refers to the directives of the EGoM. The 'gas utilisation policy' for gas produced from NELP 'D-6' is in Table 12.

Table 12: Gas Utilisation Policy for NELP D-6 Gas

Order of Priority
1. Existing gas-based urea plants, to enable them to achieve full capacity utilization.
2. Existing gas-based plants extracting LPG.
3. Gas-based power plants (as well as those likely to be commissioned by 31 March 2009).
4. City gas distributors, for sale to the transport and household sectors only.
5. Gas-based steel plants that hold APM allotments but have not received gas due to non-availability.

Source: Empowered Group of Ministers on Gas Allocation, 25 June 2008

The EGoM later amended the order of priority to allow the Ministries of Fertilisers and Power to allocate gas to individual units *within* the sectoral caps. Table 13 shows allocations by sector, for two tranches of D-6 gas. However, some units could not utilise their allocations, as pipeline connections failed to be carried out in time. Therefore, there are no accurate figures for the number of sale agreements and actual consumption.

[41] For example, the NELP 'CB-ONN-2000/2' block in 2002; the Panna-Mukta-Tapti finds under the Discovered Fields Policy in 2005.
[42] Ministry of Petroleum, 2 August 2006.Can be viewed at http://pib.nic.in/release/rel_print_page1.asp?relid=19397

Table 13: Allocation of NELP D-6 Gas (in mmscmd)

Consuming Sector	Initial allotment from the first tranche (April 2009) [A]	Off-take as on 1 November 2009 [B]	Second allotment on firm basis (Oct 2009) [C]	On 'fall-back' basis [D]	Total allocations [A]+[C]+[D]
Fertiliser	15.3	13.0	0.2	-	15.5
Power	18.0*	22.0	13.2	12.0^	43.2^
City Gas	5.0**	0.8	-	2.0	7.0
LPG	3.0	2	-	-	3.0
Steel	3.8	2.5	0.4	-	4.2
Petrochemicals	-	-	1.9	-	1.9
Refineries	-	-	5	6.0	11.0
Column Totals	**45.1****	**40.3**	**20.7**	**20.0**	**86.8**

Source: Ministry of Petroleum, 2009[43]
* Includes 2.7 mmscmd for the Dabhol Power Plant;
^10 mmscmd for Captive Power Plants;
** Up to a maximum;
Note: Fall-back refers to additional 'backup' supply.

The EGoM also announced that it would decide gas utilisation for *all* NELP gas contracts (existing and future contracts). Consumer identification would be carried out on a recurring basis for each new instance of gas production.[44] Clearly, this meant that the conflict between marketing freedom and gas utilisation would continue to be unresolved, as policymakers could continue to change policy with every recurring instance of gas production.

Thus, policymakers' interpretations of NELP have gradually shifted, starting from a liberalised regime, to one where gas allocation would be prioritised sectorally by the government, and eventually to one where gas allocation would be prioritised sectorally *and* for individual gas consuming units within sectors.

The Supreme Court ruling in May 2010, on the RIL versus RNRL gas pricing dispute, upheld the absolute government ownership of the gas, effectively making it necessary for the government to issue a formal, comprehensive gas utilisation policy *ex ante*, in the near future. The implications of this decision are complex, as in a sense any sort of gas utilisation policy would in principle go against the concept of a market-oriented gas sector. Yet, it also reduces short-term uncertainty about what quantities can be sold to which users. The relevance and effectiveness of gas allocation will depend to a great extent on future changes in gas prices.

There are three potential impediments to the implementation of a formal gas utilisation policy, which could change matters. First, as long as pipeline infrastructure continues to be

[43] Can be viewed online at http://www.pib.nic.in/release/rel_print_page1.asp?relid=54138
[44] Ministry of Petroleum and Natural Gas; Can be viewed online at http://petroleum.nic.in/PressReleaseNelp.htm

underdeveloped, allocation will be effective only up to a point. Second, a gas utilisation policy is implementable practically only so long as the major portion of the main consuming sectors continues to function under public ownership. This brings us back to the fact that much of the distortion currently lies on the consumer side. Reforms in the power sector began in 2003, and a new Urea Investment Policy was announced in 2008; these both aim at increasing the share of private investment in these sectors (they are discussed later in this paper). Third, the relevance of allocation may change if gas prices increase to higher levels.

5.4 Reconciling the Conceptual Conflict within NELP: Policy Provisions

As discussed in Section 5.2, NELP Production Sharing Contracts from the seventh round onwards have contained two conflicting clauses; the provision of marketing freedom to gas producers, and the right of the government to prioritise allocation of gas to different consuming sectors. A set of policy provisions was introduced to reconcile these conflicting objectives, through amendments to the Model Production Sharing Contract from NELP VII onwards. These provisions include liberal price discovery mechanisms, uniform prices for NELP gas, and a distinction between the 'price' and 'value' of gas. Although stakeholders in the gas sector are generally aware of these policy tools, their purpose has often been a source of perplexity. In this section, as part of the larger objective of this paper, we attempt to go behind the thinking of policymakers on these policy instruments.

The government's 2007 clarification on the allocation of NELP gas led to two immediate problems; first, it meant that 'prioritised' sectors which had until then been receiving APM gas at low prices could potentially be exposed to higher prices under NELP gas, which in principle went against the purpose of the allocation mechanism.[45] And second, it infringed the marketing freedom of producers, giving rise to concerns that they would have to bear the costs of any subsidy. In the eventuality of higher prices, the government would have had two immediate options; passing on the higher cost to consumers, or bearing a higher subsidy bill.

In order to reconcile conflicting objectives without exercising either of the above options, policymakers carried out two amendments to the NELP contract. First, they introduced the concept of 'uniform prices' for NELP gas.[46] This mandated the application of a common gas price across all consuming sectors. Second, the uniform price was to be arrived at by gas producers themselves, through a process of independent 'price discovery', in order to achieve prioritised allocation without

[45] The purpose was presumably to enable the main gas consuming sectors to continue receiving subsidised gas, which was easily done under subsidised prices.
[46] Article 21.3.1(gas utilisation policy) and Article 21.7 (uniform pricing), Model Production sharing Contract, NELP VII.

violating marketing freedom and the arm's length principle.[47] The price discovery process was expected to lead to a notional market price for gas. The very first price discovery process was undertaken and implemented for NELP KG-D6; it involved the use of a pricing formula;

$$\mathbf{SP = US\$\ 2.5 + (CP - 25)^{0.15} + C}$$

Where SP is the sales price, CP the price of crude oil with a ceiling of US$ 60 and floor of US$ 25, and C is a 'biddable' component (the pricing system is analysed in Section 6.1.3, Box 1). Producers were free to seek 'quotes' on the biddable component from gas consuming sectors as part of this process.

As prices under the formula were subject to some volatility, policymakers felt the need to introduce another amendment into the NELP contractual terms to protect the share of government take (profits and royalty). A distinction was therefore made between 'value' and 'price', and the amendments required that government take be calculated on the basis of value and not price.[48]

Further, in the event of the price exceeding the value of the gas at any point in time, the amendment stated that the higher number would be taken as the 'value', and therefore the basis for determining government take. On the other hand, if the price dropped below the value, government take would be calculated on the basis of the original value. Article 21.7 of the Contract was amended, effective from NELP VII onwards, to assure producers that the approved price would also be applicable to prioritised sectors.

These policy provisions ensured that the government achieved its objective of retaining control over the allocation of gas, without contractual infringement. Thus, on the one hand, producers were assured protection of their marketing freedom through the right to 'discover' the price of gas. On the other hand, the government retained its right to carry out prioritised gas allocation through the application of uniform prices, and also ensured that its share of profits and royalty remained unaffected, through the use of the distinction between value and price as, in practice, no producer would have the incentive to set a price below the 'value', as this would mean it having to pay out the government take from within its own resources. The entire set of policy tools adopted through amendments to NELP VII appeared, therefore, to be aimed at tying up loose ends in contractual arrangements, and postponing decisions on the reform of the downstream subsidy regime involving distribution companies which continued to bear the price increases.

[47] Articles 21.3 and 21.6.1, NELP Model Production Sharing Contract, NELP VII
[48] Article 21.7, pp. 65, NELP Model Production Sharing Contract. Can be viewed online at http://petroleum.nic.in/nelp3.pdf.

Although the contractual concepts incorporated into NELP from the seventh round onwards were theoretically valid, in practice there is considerable ambiguity over the operation of the amended clauses and, specifically, on the method for determining value and price. Confusion has also frequently arisen over the inclusion of a 'bidding' component in the price discovery process, where bids for quantities can be sought by producers from gas consuming sectors. The confusion lies over whether the bidding mechanism has anything to do with the price per se, as there are some indications that it was included to aid policymakers in the determination of gas allocation to priority consumers within the proposed sectoral caps, in the case of demand exceeding the quantity available.[49] In case of the latter, higher bids would indicate higher needs. This concept is flawed, as it does not take into account the possibility of consuming sectors gaming the system, creating further distortions. The price discovery process is also complex, as it does not specify the manner in which 'quotes' can be sought; therefore in some cases producers have arrived at prices based on quotes sought from only two gas consuming sectors (power and fertilisers), meaning that the notional market price may not be reflective of the entire consumer market.

Essentially, the price discovery process and the concept of a 'notional' market price is ambiguous, particularly since, as we have seen in Section 4, it is difficult to 'assess' a market for gas in India. Although guidelines for the discovery process based on general pricing principles were released by the Committee on pricing, no official pricing policy was announced or agreed upon. As discussed above, part of this may have been because policymakers wished to retain their right over allocation, by remaining flexible over pricing, in an attempt to not violate the contractual clauses within NELP that guaranteed marketing freedom to producers – effectively, due to the 'middle' position adopted by policymakers. Yet, price is one of the most important aspects of policy. The pricing formula above was a result of the first-ever price discovery process under NELP, and had no precedent. This leaves the question of what the price of gas should be, or how it should be determined, still open to debate.

5.5 Gas Utilisation Policy and Pipeline Infrastructure

Gas utilisation policy is closely related to the development of pipeline infrastructure.[50] Logically speaking, an optimal pipeline network would take into consideration regional aspects of gas production and gas use. In general, coal reserves are located in the east, hydro in the north and north-east with some hydro in the south, and offshore oil and gas in the eastern and western parts of India.

[49] 'EGoM clears gas pricing formula for KG-D6 block', Ministry of Petroleum Press Note, 12 September 2007.
[50] Appendix I contains a pipeline map for India.

Table 14: Regional Composition of (Net) APM Gas Production in 2009 (in mmscmd)

Region	*State*	*Gas Production*
East	West Bengal	0.01
West	Gujarat	6.59
	Bombay High (Offshore)	36.85
South	Tamil Nadu	3.19
	Andhra Pradesh	4.05
North-east	Assam	7.54
	Tripura	1.54

Source: Petroleum Plannind and Analysis Cell**,** Ministry of Petroleum, 2009
Note: Figures may be subject to small variations**.**

Gas-fired power plants have developed along the west coast due to ease of access to LNG terminals. Urea plants have also developed along the coastline, close to offshore fields, LNG terminals, and refineries. 72 per cent of gas-fired power generation is in the western and southern regions, which together account for 66 per cent of total industrial electricity consumption. The north has the largest power deficit; it also has a high percentage of captive power consumption (around 40 per cent). The north contains large concentrations of the urea industry, close to its main markets. As it is cheaper to transport gas than to transport the finished product to market, there is a large requirement for gas. Most manufacturing facilities in the north lie at the tail end of the HVJ pipeline.

While the western part of Indian has easy access to LNG and domestic gas from offshore fields, the southern part is serviced by the East–West pipeline (operated by RGTIL). However, gas on this pipeline is first transported to the west before distribution to other regions. The north, and to an extent the south, are therefore potentially the largest future demand centres for gas.

Prior to NELP, policy on pipelines was administered within an entirely publicly-owned and operated sector, with GAIL as the only gas transportation company. The dynamics of the sector changed very quickly after the launch of NELP, when the volume of gas production from private producers began to increase rapidly.

Table 15: Regional Distribution of Gas-Based Demand for Power

Region	Demand (%)	Population (Millions)	GDP (US$ billions)
East	1.00	227.47	92.46
West	47.0	230.08	165.61
North	22.0	306.77	162.40
South	25.0	223.31	157.68
Northeast	5.00	38.32	15.48

Source: *All India Electricity Statistics: General Review*, Central Electricity Authority, Ministry of Power, 2008; Planning Commission Databook, 2010
Note: Figures for population (2001 Census) and GDP exclude Union Territories;
GDP data for 2008 at constant (1999–2000) prices.

In 2006, all pipeline issues were transferred to the downstream regulator – the Petroleum & Natural Gas Regulatory Board.[51] Prior to this transfer, the government had received a number of applications to lay pipelines, and whilst approving these, it did not impose guidelines regarding coverage in order to ensure sectoral priority, or supply to deficit regions. Under the NELP terms, private gas producers expected freedom in the choice of a carrier, and in the building and operation of gas pipelines. Discoveries in the eastern offshore basin required a large pipeline network to transport the gas to geographically distant locations, making it necessary to step up investment in pipelines through private participation. These companies needed Right of Use over land, which the government initially secured for public and private sector oil and gas companies.[52] These, and related issues, prompted the government to formulate a pipeline policy in 2006.[53]

While a formal statement on pipeline policy was released in 2006, a formal clarification on gas utilisation policy was announced in 2007. The lack of synchronicity between the two has led to situations where gas allocations have not been used due to the lack of pipeline connectivity.

Table 16: Existing and Proposed Gas Pipelines (in km)

Name of the Developer and Pipeline	Existing	Proposed
Gas Authority of India Ltd. (GAIL)		
HVJ	3100	-
Others	3700	-
Upgraded and new (2012)	-	4500
Indian Oil Corporation Ltd.		
Regional and Trunk	-	133
Gujarat State Petroleum Corporation Ltd.		
Regional pipelines	1200	-
Trunk and regional	-	2600
Oil India Ltd		
Regional	500	300
Reliance Gas Transmission Infrastructure Ltd.		
East West Pipeline	1400	-
Regional and Trunk	-	2175
TOTAL	**9900**	**9708**

Source: Various published sources; 16th Report of the Standing Committee on Petroleum and Natural Gas, 2007

The Pipeline Policy of 2006 gave pipeline developers the freedom to transport gas to consumers of their choice. The main developers (GAIL, Gujarat State Petroleum Corporation, and RGTIL) initially proposed pipeline routes which best suited their marketing plans. These included

[51]Section 11 of the '*Petroleum & Natural Gas Regulatory Board Act, 2006'* deals with functions of the Board. Can be viewed online at http://petroleum.nic.in/regbill.pdf.
[52] '*Petroleum Mineral Pipelines (Acquisition of right of user in land) Act, 1962'*, Can be viewed online at http://ppac.org.in/notifications/petrolact.html.
[53] Policy for gas pipelines, '*Gazette of India',* 20 December 2006; can be viewed online at http://petroleum.nic.in/ngnotification.htm.

transferring eastern offshore gas to the prosperous markets of Maharashtra and Gujarat on the west coast. The gas could then be connected to the HVJ pipeline, and brought to the north. The downstream regulator recently announced regulations for authorising both trunk and city gas pipelines. Significant expansion is planned, doubling connectivity by 2012.

Despite this expansion, there are fundamental issues that are a prerequisite to a competitive and well-functioning pipeline network. First, the functions and jurisdiction of the downstream regulator are unclear, especially with an announcement in 2009 of a 'Natural Gas Highway Development Authority' that would be directly funded by the centre to lay a pipeline network across the country. Pipelines are natural monopolies and require regulation; formal clarity on the definition and functions of an independent regulator for pipelines is crucial to the future development of the sector. And second, whilst the concept of an 'arm's length' relationship exists on the upstream (production) side, there is no such relationship in the regulations on pipeline connectivity, and no universal service obligation.

5.6 Gas Utilisation Policy: Summary of Observations

In summary, the gas utilisation policy is a curious and complex system. It underpins much of the 'dissonance' between upstream and downstream sectors. Gas utilisation policy was originally introduced as an integral function, as part of the planning system. After liberalisation, gas utilisation policy, which had applied mainly to administered (APM) gas, was worked into the contractual terms of the NELP production sharing regime, which is an illustration of the conflict of objectives that may occur in the process of transition, when market-oriented reforms are attempted by policymakers using a planner's mindset.

The gas utilisation policy, in practice, may not have served the same purpose in all sectors. For instance, as we discuss later on, there is a greater role for gas in the fertilisers sector – where there is a direct link with the agricultural sector and farmers, and where manufacturing processes require, and are being reoriented towards, the use of gas as a primary input – than in the power sector, where the role of gas is primarily to be found within segments such as captive and merchant generation, and where power from these segments is mainly used by industry and other large users that are affected by blackouts and shortages on the state grid. Yet, under the gas utilisation policy for NELP D-6 gas, the power sector actually received more gas than did the fertilisers sector (Table 13). This may have been due to the lack of pipeline connectivity to all fertiliser plants– once again highlighting synchronicity problems – allocations made may have gone unused.

Although things are gradually changing with economic reforms, the transition has resulted largely in distortions being pushed into downstream consuming sectors. The relevance of gas utilisation policy will largely be determined by future movements in gas prices. We explore this in the next section.

6. Pricing

As discussed earlier, administered pricing was carried out in order to fulfil distributional objectives, and pricing in the Indian energy sector has long been administered, to keep the prices of final goods low. Over a period of time, for economic and political reasons, the notion of paying market prices for energy has become increasingly difficult to accept amongst large sections of consumers. This is largely because elections have typically been fought on assurances to the electorate of the public provision of essential goods at low prices.

This section investigates the issue of gas pricing using two approaches. It first investigates whether there is a market for gas as a competitive fuel substitute in its main potential consuming sectors of fertilisers, power, and city gas. Secondly, it then goes deeper into pricing *within* these main sectors and investigates the extent to which policies in downstream consuming sectors contribute to distortions in the price of gas, or conversely, to what extent changes in sectoral policy in downstream consuming sectors could contribute to the removal of bottlenecks in the transition of the gas sector to a market-oriented form of operation.

6.1 Pricing Regimes in the Indian Gas Sector

There are three gas pricing regimes in India. Under the first regime, prices of APM gas and gas produced from Joint Ventures under the 'discovered fields' exploration policy are set by the government (for NOCs), or according to a fixed formula (for private companies in the Joint Venture). The second regime covers re-gasified LNG, where prices are determined on the basis of long term and short term contracts, and spot purchases.

Table 17: Prevailing Gas Prices in India, 2010

	Source	Regime	Price (US$/mmbtu)
1	**APM Gas**	APM	4.20
2	**Panna–Mukta–Tapti fields**	Discovered Fields	4.60 – 5.65
3	**Ravva field**	Discovered Fields	3.50 – 4.30
4	**Lakshmi and Gauri fields**	Discovered Fields	4.60 – 4.75
5	**Hazira field**	NELP	4.65
6	**D-6**	NELP	4.20
7	**LNG (Spot Prices)**	Imported Gas	7.00 – 10.00

Source: Compiled by authors
Note: LNG spot prices in the USA have been falling, due to the effects on the market of shale gas.

The third regime covers NELP gas, under which gas producers can 'discover' the price of gas themselves, but are required to get its 'value' approved by the government. The third regime is still evolving. As NELP gas will overtake the production from APM and 'discovered fields', the third

pricing regime is the most relevant. Multiple gas pricing regimes have resulted in gas in India being sold at different prices. Table 17 shows the producer prices for gas. We briefly examine each regime in further detail.

6.1.1 Pricing under the APM and Discovered Fields Regime

APM gas was mainly used to supply the main gas consuming sectors. In pricing to final consumers, gas prices were lowest for the power, urea, and city gas sectors, and higher for other (non-APM) consumers.

Table 18, below, illustrates the pricing of APM gas to consumers, by region and consumer category. NOCs were originally paid for their gas on a cost-plus basis. However, policymakers failed to review (and update) this basis, and therefore the level of 'under-recoveries' (discussed in Section 3) rapidly grew. ONGC recently reported a potential loss of over Rs 40 billion (nearly US$ 900 million) in this segment of its business due to the poor sales realization of APM gas, which comprises 80 per cent of its total production.

As discussed, the government has raised the APM price to match the price of NELP D-6 gas, (US$ 4.2 per mmbtu). If distortions (input and output subsidies) in gas consuming sectors had continued, this would have continued to affect NOCs' finances. However, recent policy announcements have included the intention to provide the subsidy through the government, directly to the distribution company in the main gas consuming sectors (specifically, fertilisers) rather than through NOCs. These measures in combination signal a removal of part of the distortion, and of the opaque subsidy element in pricing.

Table 18: Pricing of APM Gas to Consumers *prior* to Gas Price Increase (US$/mmbtu)

		APM CONSUMERS		NON- APM CONSUMERS
	Network/Region	**Power and Fertilisers Sectors**	**Price applicable to small consumers (allocations up to 50,000 SCMD) and City Gas Distribution companies**	**Price applicable to Non-APM Consumers (including internal consumption by GAIL)**
1	Mumbai, South Gujarat & along HVJ pipeline	**1.88** (1 July 2005)	**2.26** (6 June 2006)	**4.75** (1 April 2006)
2	Krishna Godavari (KG) Basin and Cauvery	**1.88** (1 July 2005)	**2.26** (6 June 2006)	**3.50** (1 August 2006)
3	North Eastern Region	**1.13** (1 July 2006)	**1.36** (6 June 2006)	**1.88** (1 July 2005)

Source: Report on Supply, Distribution, and Marketing of Natural Gas, 2007[54]
Note: Parentheses contain date from which prices became effective; original data in mmscmd converted by authors

[54] Sixteenth Report on Supply, Distribution and Marketing of Natural Gas, pp. 13, paragraph 1.10, Standing Committee on Petroleum and Natural Gas (2007–08).

6.1.2 Pricing of LNG

LNG prices are determined on international markets. In India, 80 per cent of the market share of LNG is controlled by Petronet LNG Ltd., a private company promoted by a consortium of public sector organisations. Prices to consumers (especially in the public sector) have not been completely free of government influence. Petronet has a long term contract with the Qatari LNG company, RasGas, and also supplies gas on spot and short term bases. In one instance, Petronet LNG Ltd was asked by the government to pool the cheaper price of its long-term contracted supply with the higher priced short term supply for Ratnagiri Gas and Power Private Ltd (or, the Dabhol power plant), in order to moderate the price of gas supplied to Dabhol. This price (resulting from pooling the two different purchase volumes and averaging the price across customers) was applied to all customers and led to a rise in LNG prices for all existing customers. Therefore, gas supplied to Dabhol was, in a sense, subsidised by raising the price for all long term contracted buyers.[55] As the buyers were mainly Public Sector Undertakings (PSUs) there was little resistance to this administered change.

In the future, the downstream regulator (Petroleum and Natural Gas Regulatory Board) may play a role in LNG pricing to consumers, as the provisions of the Petroleum and Natural Gas Regulatory Board Act, 2006 cover pricing issues including tariffs for pipeline transportation. These provisions are common to all gas supply sources, and the Regulator has been accorded the power to fix tariffs for 'common carrier' pipelines.[56] There is a lack of clarity over the applicability of these provisions to other gas infrastructure. Therefore, the tariff of LNG terminals is currently unregulated, leading to concerns over high re-gasification tariffs in the future.

6.1.3 Pricing of NELP Gas

The NELP gas pricing regime is still evolving, and there is considerable uncertainty over how the price discovery process will operate in the future. The pricing regime in NELP, and in any future fiscal regime in gas exploration, will be crucial to incentivising private investment. As discussed earlier, as part of the policy amendments adopted to reconcile conflicting clauses in the Production Sharing Contract in NELP VII, the government made a distinction between the 'price' and the 'value' of gas. Whilst price was to be determined on an arm's length basis, the government released guidelines on valuation in June 2007.[57]

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[55] Recently, however, D-6 gas has replaced the shorter contracted supply.
[56] Section 11, Petroleum and Natural Gas Regulatory Board Act, 2006. Online at http://www.pngrb.gov.in/.
[57] Full guidelines online at http://petroleum.nic.in/reportgas.pdf; Articles 21.6 and 21.7 of NELP PSC relate to the valuation of gas. Online at http://petroleum.nic.in/nelp93.pdf.

(a) Gas should be sold at 'market' price.
(b) The royalty and profit petroleum of the government should be calculated on the basis of the value.
(c) Although the value and price could be different, the higher number should be taken as the value for the entire quantity of gas.
(d) The government's role in undertaking an exercise to determine the value of gas arises when the prices have not been determined on the basis of competitive bidding.
(e) Ideally, the value should be 'discovered' through an open bidding process.

As discussed in Section 5, the concept of value appears to have been introduced as a method of protecting the government's share in profits and royalty in the event of volatility in prices (that is, low prices). The fact that the higher number would be considered the 'value' of gas makes it necessary for the contractor to keep the approved valuation as the sale price. Thus, despite the fact that producers are allowed to 'discover' prices, it is necessary for the producers to price gas no lower than its value. This approach is, conceptually, similar to a concessions regime.

The price discovery process requires clarity on some points. In the case of D-6 gas, bids were sought in a tentative manner due to a court dispute over a part of the planned production.[58] Also, against a peak production of 80 mmscmd of gas, RIL received bids for only a part of total production, and from two consuming sectors – fertilisers and power. However, the government has permitted the sale of gas at the approved price across all consuming sectors with uniform applicability. There needs to be wider representation in bidding in future price discovery processes, and sectors such as city gas and refining could be included. As the formula has only one biddable component, 'C' (see the formula in Section 5.4 above, repeated in Box 1 below), the value/price will depend to a great extent on the quotes received for this. This requires clarity on how the government will approve differing quotes for 'C'. The role of 'C', per se, needs further definition. Although the price discovery process incorporates an element of benchmarking to the international price of crude oil, and is a step in the direction of price discovery through a market-oriented process, the pricing of gas under NELP is still arbitrary, as discussed in Section 5.4.

[58] This dispute was seemingly resolved on 7 May 2010, through a Supreme Court judgement which upheld the government's right to approve the gas price under NELP contracts.

Box 1: An Analysis of Gas Pricing Under NELP

The determination of price, or the 'price discovery' process under NELP has remained a nebulous concept, with further clarification required on several aspects of the terms in the Model Production Sharing Contract. The NELP regime does not contain specific guidelines on the determination of prices, or the price discovery process. Article 21.6.2(c) of the Contract sets out some principles; 'Gas [...] shall be valued on the basis of arm's length sales in the region for similar sales under similar conditions.' Article 21 also states that the formula for pricing needs to be approved by the government. A committee was set up in 2006 to look into the issue of gas pricing; but apart from recommending that the price discovery be undertaken through a competitive bidding process, it did not elaborate on what this process should be, but invited stakeholders to submit suggestions for the same, leaving the process fairly open to interpretation.

The conventional pricing formula used for natural gas tends to contain a mix of constants and variables. This could include a base price, and an indexation to traded liquid fuels. Earlier Production Sharing Contracts in India suggested indexation to furnace oil, but as the world trade in furnace oil declined, crude oil was later suggested as an index. The pricing of D-6 gas is the first example of gas pricing under NELP. Reliance Industries Limited (RIL) incorporated a bidding factor, 'C', into its process of price discovery. Under this, it invited bids (the bids received for the factor ranged from 1 to 10) for the value of C from companies in the power and fertiliser sectors, as well as for the quantities of gas required. As more than 50 per cent of the gas volume received bids for a value of C greater than 4, the value of C was set at 4, and RIL proposed a final price of US$ 4.33 per mmbtu based on the following formula:

$$\textbf{Sale Price} = \text{US\$ } 2.5 + (CP - 25)^{0.15} + C$$

US$ 2.5 is the constant in the formula, representing the base price of gas. CP is the crude oil price, which had a ceiling of US$ 65 and a floor of US$ 25, and C represents an average value of bids. This formula was considered by the government, which revised the ceiling downwards to US$ 60 and assigned a value of 0 to C, arriving at a price of US$ 4.2 per mmbtu, to be revised in 2014 (that is, five years after initial implementation).[59] The exponent in the formula, 0.15, gives rise to an 'S' type curve, which results in an relatively inelastic gas price (relative to crude oil price) at the upper and lower ends of the curve; the floor is typically meant to work in favour of the seller of gas, and the ceiling in favour of the buyer. However, the price of crude oil breached US$ 60 very early on in the use of the formula, and thus the formula is not fully representative of current movements in crude oil prices. There has been considerable debate over this formula and it has been argued that the inelasticity at the lower and upper ends of the curve is different, and does not result in relatively 'equivalent' outcomes in terms of gas price, when the prices of crude oil rise or fall. However, the fact remains that this was the first price discovery exercise based on the provisions of the Model Production Sharing Contract and the broad suggestions by the 2006 committee.

In earlier sections, we discussed the lack of connectedness between the producer and consumer sides in gas, and the injection of distortions into downstream consuming sectors. In the next few sub- sections, we assess pricing policy in these sectors, and the price competitiveness of gas with alternative fuels such as coal, diesel, and LPG. The government owns roughly 50 per cent of the

[59]Ministry of Petroleum and Natural Gas, 20 November 2007. Online at http://pib.nic.in/release/release.asp?relid=32847.

power sector and 80 per cent of the fertiliser sector, the two main consuming sectors.[60] Any policy changes in gas pricing are therefore closely linked with the government's subsidy bill, and likewise, price movements in consuming sectors are likely to influence the future development for gas.

6.2 Pricing in the Fertilisers Sector

The fertilisers sector is a politically sensitive area of policymaking, as around 70 per cent of India's population is employed in the agricultural sector. *Urea*, which releases nitrogen, is the most extensively used agricultural feedstock, and its price is controlled by the government. Of the three main soil nutrients – namely nitrogen, phosphate, and potash – required for various crops, indigenous raw material is available mainly for nitrogen. The production and distribution of other fertiliser products (which include phosphates and potash) have been decontrolled since the early 1990s. Urea can either be imported, or manufactured. In the case of manufacture, naphtha is a primary input, for which gas is a substitute. Volatility in the prices of naphtha and increases in the production of domestic gas have led to a policy reorientation in the past few years, which has promoted the substitution of naphtha with gas.[61] Urea can be widely used in crop cultivation, whereas potash and phosphate are crop-specific, or used in small volumes. The government's policy has been aimed at achieving self-sufficiency in the production of nitrogenous fertilisers, that is, urea (see Box 2 below).

This has involved a reorientation of technology and manufacturing processes in the urea sector, as naphtha-based plants are required to convert to gas-based manufacturing capabilities. Units producing urea undergo routine manufacturing cost audits, which vary according to the technology and age of the plant, leading to differences in production costs, and subsidies. Urea plants are classified into groups on the basis of the vintage of plants and the feedstock used. These include pre-1992 and post-1992 gas-based plants, pre-1992 and post-1992 naphtha-based plants, Fuel Oil / Low Sulphur Heavy Stock (LSHS)-based plants, and mixed-energy plants.[62]

In 2007, the total installed capacity of urea based on natural gas feedstock was roughly 67 per cent, on naphtha, 23 per cent, and on fuel oil, roughly 10 per cent. In the long term, all plants are

[60] Working Group Report for Power sector for the XI Plan (2007–12), Table 1.8, pp. 6, 2008; 26th Report on Demand for Grants submitted to the Standing Committee on Chemicals and Fertilisers, 28, 2006.
[61] The Urea Investment Policy, 2008.
[62] LSHS is a residual fuel produced from indigenous crude.

expected to convert to gas-based manufacturing.[63] Gas-based plants are more energy efficient and have lower capital investment costs compared to naphtha and fuel-oil based urea plants.[64]

Urea pricing is therefore influenced by three factors: the international price of imported urea, the international price of LNG used to manufacture urea domestically, and the price of domestically produced gas used to manufacture urea domestically. From the point of view of economics, pricing depends on the option that proves the most competitive. However, in practice, pricing is influenced by the government's objective of self-sufficiency, and by the cost of subsidies to the fertilisers sector.

Box 2: The Self-Sufficiency Objective in Indian Fertilisers

The development of a market for gas in India is closely linked with policy in its main downstream consuming sectors. As the majority (currently 70 per cent) of the Indian population is engaged in agricultural work, the demand for fertilisers has historically been high. Typically, crops are treated with a mix of nitrogen, phosphates, and potash, the optimal proportions of which are 4:2:1. Due to the dependence on agriculture, the Indian government considers food security as one of its main policy aims, and following from this, an objective to achieve self-sufficiency in the production of fertilisers. Urea is the most commonly-used fertiliser input, due to a number of factors. First, it has more nutrients (nitrogen) in comparison with phosphates and potash; second, much (but not all) of the main input for urea is indigenously produced (natural gas); and third, India has insufficient reserves of phosphates, and no reserves of potash, making imports necessary – in addition, rock phosphates and sulphur have limited availability on the international market. The government's policy objective is therefore 'to achieve the maximum possible degree of self sufficiency in the production of nitrogenous fertilisers based on utilisation of indigenous feedstock' (Report of the Working Group on the Fertilisers Sector, Eleventh Five Year Plan, 2007–12). This directly affects policy outcomes in the gas sector.

The main inputs to urea are naphtha and natural gas, which are substitutes. In the past, the government has had to import naphtha and LNG to meet the shortfall in the supply of urea inputs. It has been cheaper for producers to manufacture urea with domestic gas than with naphtha, or with LNG imported at spot prices. Overall, the production costs of gas-based plants are lower than those of naphtha-based plants. The production costs also vary according to the type of plant and fuel input used. However, the production costs are relevant in this case only in terms of their impact on the fertiliser subsidy bill. The pricing and distribution of urea is controlled, and urea manufactured from all fuels/processes is priced the same; but the production and distribution of other fertiliser inputs was (partially) 'de-controlled' in 1994 (although these continue to be subsidised, but to a lesser extent). Approximately 66 per cent of the subsidy bill goes toward naphtha and fuel oil manufactured urea, whereas 34 per cent goes towards gas-based urea. The table below indicates that whilst the cost of production of urea rose by roughly seven times during 1977–2004, its retail price went up by only three times, with the remainder financed through a subsidy.

[63] The initial target date for this conversion was set for 2010; but it was not met.
[64] Report of the Working Group on the Fertilisers Sector for the XI Plan (2007–12), 32–3. Online at http://planningcommission.nic.in/aboutus/committee/wrkgrp11/wg11_fertliser.pdf.

Year	Cost of Production (Rs./ Metric Tonne)	Retail Price (Rs./Metric Tonne)
1977	1,340	1,550
2004	9,444	4,380

Source: *Report of the Working Group on the Fertilisers Sector, Eleventh Five Year Plan.*

The table below uses data from the Report of the Working Group on the Fertilisers Sector to show a cost breakdown of urea manufactured using gas, its retail price, and subsidy. The data is from 2007, and therefore contains an estimate (US$ 6/mmbtu) of the potential delivered D-6 gas price prevailing at the time. Also, as mentioned earlier, costs vary by fuel and plant type; the data used pertains to the manufacture of urea by a fuel-oil based manufacturing plant, converted to use gas as a substitute. The data shows that the price of urea to the final consumer was about 40 per cent of its actual cost of production in 2007. In 2010, the retail price was raised by 10 per cent.

Component	Units	Cost Breakdown	In US$/Metric Tonne
Price of Gas from KG Basin	US$/mmbtu	**6.00**	**6.00**
Delivered Cost of Urea	Rs./Metric Tonne	**11,650.10**	**242.71**
Of Which:			
Energy Cost	Rs./Metric Tonne	6,569.35	136.86
Capital Related Costs	Rs./Metric Tonne	2,980.94	62.10
Conversion Charge	Rs./Metric Tonne	1,200.00	25.00
Freight/Distribution margins	Rs./Metric Tonne	300.00	6.25
Maximum Retail Price	Rs./Metric Tonne	**4,830.00**	**100.63**
Concession on Urea (Subsidy)	Rs./Metric Tonne	**6,820.29**	**142.09**

Source: *Report of the Working Group on the Fertilisers Sector, Eleventh Five Year Plan*, Annex 12.7, 180.
Note: Approximate exchange rate used US$1=Rs. 48; data from 2007

The production of fertilisers is a continuous process, whereas the demand for fertilisers is seasonal. The demand for urea is to an extent dependent on the quality of the monsoon (which determines the total 'crop sown' area), which in turn can be unpredictable. Therefore, in the past, the government has also had to import urea at very high prices from the international market to meet post-monsoon rises in demand. Agricultural policy is a politically sensitive issue in India, and it is likely that the self-sufficiency objective is aimed at reducing any uncertainty in the supply of agricultural inputs. However, the reduction of uncertainty does not necessarily equate with keeping prices persistently low whilst costs of production continue to rise, as this pushes the problem further into other sectors of the economy. It results in the creation of a different economic problem which may cause greater difficulty in the long-term. Moreover, the average mix of fertiliser input (nitrogen, phosphates, and potash) used in India is 7:2:1, indicating that distortions may also have been created in consumer choice, particularly with respect to the overuse of urea at very low prices.

Until the mid-1990s, the domestic cost of manufacturing urea was higher than its import price. After the start of urea manufacturing with (subsidised) APM gas, the domestic cost of production declined. In 2000, international urea prices fell as India and China expanded their indigenous capacity. However, in the last few years, international prices of urea rose significantly.

Table 19: Urea Prices, Imports, and Subsidies, 2003–09

Year	Domestic Production of Urea (MMT)	Imports of Urea (MMT)	Average International Price (FOB per metric tonne in US$)	Subsidy Disbursed on Urea (US$ Billion)	
				Domestic Production	Imports
2003–04	19.2	0.14	156	1.775	Nil
2004–05	20.3	0.64	202	2.134	0.103
2005–06	20.1	2.06	243	2.179	0.312
2006–07	20.3	4.72	257	2.635	1.056
2007–08	19.9	6.93	341	3.427	2.070
2008–09	19.9	5.67	246 – 815	4.369	2.694

Source: 'International Fertiliser Scenario', Department of Fertilisers, Ministry of Chemicals and Fertilisers, 2008.
Note: Exchange rate 1US$ = 48 Indian Rupees

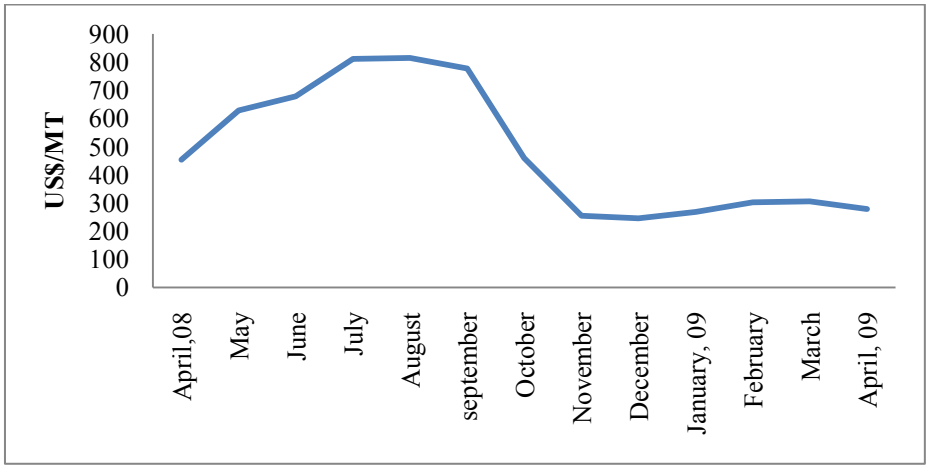
Table 19 shows that the import costs of urea have steadily increased; simultaneously, the subsidy on imported and domestically produced urea also increased (more than doubled) between 2005 and 2008. The gap between the cost of manufacturing and the sale price of urea, even whilst using subsidised gas as an input, has grown since the late 1990s, as the price of urea sold to final consumers was not raised between 2002 and 2010. In order to administer the urea selling price, policymakers kept the price of gas low and increased the per unit subsidy on urea, pushing up subsidy costs and reinforcing price distortions in the gas sector. Low gas prices (due to limited domestic supply), could not, however, contain the impact of rising naphtha and international urea prices.

The hesitation to rely on LNG may be related to the government's self-sufficiency objectives in general, and self sufficiency in urea manufacturing in particular. International prices of urea have been extremely volatile in recent years; Figure 7 shows price movements between April 2008 and April 2009.

Given the volatility in the international price of urea, in 2008, the government began a long-term reorientation towards manufacture of urea with domestic gas. If India is to meet its requirements for urea entirely through indigenous supply, it needs 76 mmscmd of gas, against current gas consumption in urea of around 30 mmscmd.[65] A potential bottleneck is the expansion of urea manufacturing capacity. Between 2007 and 2009, urea imports were roughly 6 MMT per annum. A short-term option that has been suggested by policymakers is to revive a number of closed urea manufacturing plants, which could add 5 MMT to existing capacity. The remaining requirements could be met by new capacity. [66]

[65] This was prior to the start of production from D-6, which added another 13 mmscmd to supply.
[66] 26th Report of the Standing Committee on Chemicals and Fertilisers (2007–08).

Figure 7: International Price of Urea, 2008–09 (US$ per Metric Tonne)



Source: Department of Fertilisers, 2009

The government announced a new Urea Investment Policy in 2008, with the intention of expanding domestic capacity in urea manufacturing. This policy supports urea projects in revamped (improved) capacity, expanded capacity, revival of previously closed plants ('Brownfield' plants), and greenfield urea projects. It benchmarks the purchase price of urea to the price of NELP (D-6) gas, by setting a floor and a ceiling for the purchase of urea from domestic manufacturers and from potential Joint Venture projects abroad. As the price for the purchase of urea from domestic manufacturers has been linked to the price of NELP D-6, and as the NELP regime currently requires gas prices to be reviewed every five years, it is likely that when D-6 gas prices are revised in 2014, urea prices will change as well.

Under this policy, the ceiling on the purchase price of urea will be US$ 425 per metric tonne (benchmarked to D-6 gas prices) and the floor will be set based on Import Price Parity of urea from the Gulf States. All new urea capacity will be governed by NELP gas prices (subject to five-yearly revisions), whilst existing capacity will be governed by the price of APM gas (which is, at the time of writing, equivalent to NELP D-6 gas). The policy requires that investors make independent arrangements for procuring gas. It appears to rule out LNG as a substitute for domestic gas, and presumes that international prices of urea will not remain high.

How does the pricing of fertilisers stand in relation to the pricing of gas in India? First, although the Urea Investment Policy signals a move towards pricing reform in the fertiliser sector, the success of the policy in contributing to the removal of distortions in gas prices will depend entirely on the speed and extent to which new investments in urea manufacturing occur. This is evident from the fact that only new urea capacity will be governed by NELP gas prices. We know that although APM gas prices have recently been raised, so far there are no indications of regular future revisions,

or benchmarking of APM gas to international prices. This implies a dual pricing regime in urea. Second, as investors in new urea capacity have to make 'independent arrangements' for obtaining gas, gas allocation could result in a shortfall in supply to this new capacity.

This suggests that the starting point to removing price distortions in the fertiliser sector may not lie in capacity addition and self-sufficiency in manufacturing capacity, but in *rethinking* the objective of self-sufficiency, especially when it is taken to mean the assured supply of inputs at prices that are persistently kept below (rising) costs of production, as this has little economic justification. In fact, this policy has actually served to create an imbalance in the use of fertilisers by farmers. As mentioned in Box 2, the optimum mix of fertiliser input is 4:2:1. However, data for 1985–2005 shows that there has in fact been an overuse of nitrogenous inputs (urea), with the actual proportions being 7:2:1, on average.[67] This suggests that policymakers need to consider a different approach to the problem of uncertainty in the manufacture of fertiliser inputs, which is based on comparative advantage rather than absolute advantage. This would involve looking at fuel substitution options which result in the lowest opportunity costs and the highest relative efficiency of production. We return to this in Section 7.

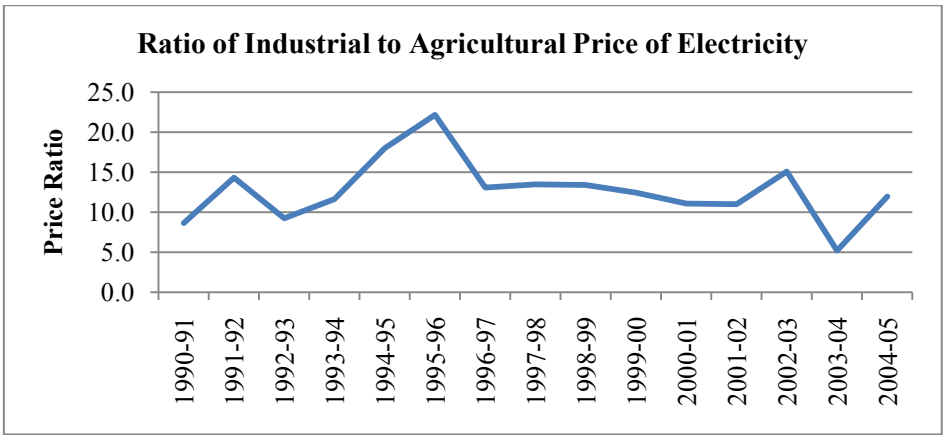
6.3 Pricing in the Power Sector

The majority of installed capacity in power is state-owned, and power is provided at heavily subsidised prices to specific consumer segments. The main distortion in power pricing has its origins in political economy and the system of administered prices for achieving distributional objectives. The power sector was nationalised in the years following independence in 1947. In the Indian federal system, Indian states have considerable autonomy over policy in the power sector, subject to federal guidelines and national legislation.

State Electricity Boards were set up to administer generation, transmission, and distribution of power in each state; these were vertically integrated organisations that operated on the basis of economies of scale and cross subsidies to extend access to electricity to the entire Indian population.

[67] Annex 3.4, pp.40, Report of the Working Group on Fertilisers, Eleventh Five Year Plan; and Report of the Working Group on Crop Husbandry, Agricultural Inputs, Demand and Supply Projections and Agricultural Statistics for the Eleventh Five Year Plan, pp.28.

Figure 8: Cross Subsidisation between Industrial and Agricultural Electricity Price



Source: Sen & Jamasb (2010)

Around the late 1970s, the power sector began to be used by incumbent governments as an electoral tool. Agricultural consumers, who formed the largest proportion of the electorate, were promised electricity at very low or zero prices, and this practice very quickly became entrenched.[68] This was sustained through direct subsidies and through cross subsidisation by charging higher prices to the industrial consumer sector. Figure 8 above shows the extent of this cross subsidisation between industry and agriculture, by graphing the ratio of industrial to agricultural prices of electricity in India.[69]

The ratio is driven by a rising industrial price of electricity, in comparison with a relatively static agricultural price of electricity. Consequently, the average cost of electricity began varying inversely with its average price. As free electricity to farmers implied a zero marginal value on its consumption, this led to wastage, lack of metering, and mounting commercial and technical losses. This eventually led to a situation where State Electricity Boards became financially insolvent, and the system began collapsing, initiating the beginning of power sector reforms in the early 1990s. Reforms in India have followed the generic model of electricity reform; namely, legislation, unbundling, corporatisation, independent regulators for each state, measures aimed at price corrections, and (optionally) privatisation of generation and distribution. However, states retain their autonomy over the process, and have progressed differently in the manner and pace of reform.

Initial attempts at reform had mixed outcomes, and the lack of capacity addition between the mid-1990s and mid-2000s has led to massive peak and overall energy deficits. On a PPP basis, Indian

[68] The first instance of free electricity has been traced back to the 1977 elections for the Andhra Pradesh state legislature (Tongia, 2003).
[69] This is based on the ratio of industrial to residential price of electricity, a conventional indicator of cross subsidies in developed countries. See Sen and Jamasb (2010) for a discussion on the industrial to agricultural price ratio.

energy prices, particularly for industry, are some of the highest in the world (Report of the Expert Committee on Integrated Energy Policy, Planning Commission, 2006).[70] Much debate exists over the distortions created by this, and it has been only recently, under the provisions of the Electricity Act 2003, and policy directives that have followed, such as the National Tariff Policy and National Grid Plan, that extensive reforms have been initiated towards correcting these distortions and creating competition. Reform measures that relate to generation are directly relevant to gas pricing.

6.3.1 Power Sector Reforms

The viability of gas in the power sector depends largely upon its cost competitiveness compared to coal, which in turn is closely related to the process of power sector reforms. At the time of writing, two-thirds of supply to gas-based power plants is at subsidised rates, through APM gas.[71] The two most relevant aspects of reforms relate to provisions to liberalise grid capacity through the measures of power trading and third party access,[72] and measures towards rebalancing of the inverse relationship between average cost and average electricity price. Third party access will facilitate the harnessing of electricity produced from merchant and captive power plants, which have been projected as future growth areas for gas demand. According to the Electricity Act 2003,[73] a generator has three options through which to sell power; first, to distribution companies by winning 'bids' based on prices; second, by selling directly to a customer or to a distribution licensee for short term sales using open access regulations; and third, to an electricity 'trader'. Captive power plants can sell surplus electricity using the first two options.

Reforms also include the addition to generation capacity through 'Ultra Mega Power Plants' (plants with an installed capacity greater than 4000 MW. There are currently 14 of these under construction or being planned (on a Build-Own-Operate basis) in nine states. An important aspect of these plants is fuel linkage. Under this policy, distributors must 'bid' for the purchase of power from generators.[74] From January 2011 onwards, under the National Tariff Policy, bidding will form the

[70] Report of the Expert Committee, Integrated Energy Policy, Chapter 5.2, Planning Commission, 2006. Online at http://planningcommission.nic.in/reports/genrep/rep_intengy.pdf

[71] About 25 mmscmd of APM gas was supplied to the power sector at the beginning of 2008 out of the total gas-fired power consumption of 38 mmscmd.

[72] This entails permitting the use of the state grid to private generators, to wheel power to consumers. In India, Open Access is subject to a 'wheeling charge' and a more controversial 'cross subsidy surcharge' imposed by states to make up for the revenue lost from consumers that opt out of the state grid. Open Access is being introduced by states in phases, based on consumer size.

[73] A 2003 legislation consolidating all previous policy on the power sector.

[74] The Ministry of Power permits two types of 'bidding'. Under 'Case 1 Bidding', the generator is free to produce power from any fuel, while in 'Case 2 Bidding' the fuel type is specified and the government provides fuel linkage. 'Case 1 Bidding' is more flexible, but has not yet come into operation.

basis of power purchase by distributors, and public and private generators will have to compete.[75] Due to the fact that no gas allocation has been made from the D-6 fields to new, greenfield, power plants, bids have so far been made by distributors only for coal-based capacity. Gas faces significant price competition from coal. As 90 per cent of coal production is subsidised, electricity produced from coal is cheaper than from gas. Also, as coal mines are completely state-owned, fuel linkages for domestic coal are easily provided to both public and private generation companies through government policy. Domestic gas, however, lies increasingly in the private sector, and currently the only method of linkage to gas is through the gas utilisation policy.

The above brings out the extent of distortions in pricing in the power sector; in order for there to be a level playing field, there would either have to be equivalent linkages provided for gas-based capacity, or, there would have to be reforms in the coal sector. In the short term, the only conclusion that can be made is that it will be difficult for gas to compete with coal for base load generation. This highlights the issues which have to be faced in the coal sector; any integrated policy on energy will have to take into account the fact that most fuel options will be unable to compete with coal at its current level of prices and policy.

It can be argued that opportunities for the growth of gas-fired generation in the energy sector exist due to the energy deficit, which is likely to persist in the short term. However, the underlying assumption here is that, under the present system, the demand for gas is based mainly on failures in the generation sector, which may not be inevitable, and the first-best here would be to reform the generation sector per se. The viability of gas in power generation will therefore depend to a great extent on its cost competitiveness compared with other fuels, especially coal.

6.3.2 The Competitiveness of Gas-Based Power

As gas-based power is likely to be more expensive than coal-based power, it will be viable only in specific segments of the power market. One such niche segment is the captive and merchant power sector. Another segment is power that is traded across states, using trading platforms operated by 'power exchanges'. There are two exchanges in India, in operation since 2007, and the total volume of electricity traded in 2007 was roughly 3 per cent of total generation from utilities, although this is likely to increase.[76]

Although most tradable power will be produced by merchant plants, the 'Ultra Mega Power Plants' are also permitted to trade part of their generation. This could help the price competitiveness of gas-

[75] National Tariff Policy. Online at http://www.powermin.nic.in/acts_notification/electricity_act2003/pdf/Tariff_Policy.pdf.
[76] *All India Electricity Statistics General Review 2009*, Central Electricity Authority (CEA), May, 2009, 187.

based power, as the higher generation costs could be passed on to the tradable component. Merchant power plants that have surplus power can make profits by selling this surplus to meet peak demand, as power supplied under this category is not under long term contracts. It has been suggested that several merchant power plants are being set up purely on the feasibility of a small share of their capacity being sold commercially at high prices through the power exchanges.

The price of traded power during 2007 is shown in Table 20, which reveals that nearly 44 per cent of traded volumes fetched prices over Rs 5/kWh (or roughly US$0.104 /kWh). The weighted average sale price of traded electricity increased by 60 per cent, from Rs 4.52/kWh in 2007 to Rs 7.29/kWh in 2008.[77] This could be due to increased power trading (as the amount of generation in the private sector based on power trading increases, the weighted average also increases).

Table 20: Volume of Electricity Traded by Price, 2007

Price (Rupees/kWh)	Volume (GWh)	% of Total Volume
0.00–1.00	253.33	1.21
1.00–2.00	4,476.28	21.35
2.00–3.00	2,079.86	9.92
3.00–4.00	2,153.38	10.27
4.00–5.00	2,681.42	12.79
5.00–6.00	3,464.65	16.53
6.00–7.00	2,528.50	12.06
7.00–8.00	2,765.88	13.19
8.00–9.00	539.41	2.57
9.00–10.00	17.51	0.08
10.00–11.00	2.07	0.01
11.00–12.00	2.47	0.01
Total	**20,964.77**	**99.99**

Source: Central Electricity Authority, 2009

A study of price trends reveals that electricity prices have been largely static in the agriculture and domestic sectors, while they have been rising elsewhere. Table 21, below, shows the range of maximum and minimum average price rates for electricity in India. Table 21 shows that larger industrial consumers are charged lower prices than small industrial consumers, and commercial establishments (mainly services) are charged the highest.

[77] *Economic Survey, 2008–09,* Government of India, Table 9.9, 228.

Table 21: Maximum and Minimum Average Rates of Electricity, 2007

	Category	Max (Rs/kWh)	Min. (Rs/kWh)
1	**Domestic**	6.49	0.40
2	**Commercial**	11.06	0.52
3	**Agriculture**	4.79	0
4	**Small Industries**	8.00	1.96
5	**Medium Industries**	8.72	1.96
6	**Large Industries At 11 KV**	7.16	0.67
7	**Large Industries At 33 KV**	5.72	0.67
8	**Power Intensive Industries**	4.13	1.48
9	**Railway Traction**	6.18	3.59

Source: Central Electricity Authority, 2008
Note: KV refers to the voltage levels at which industries receive power from the grid

In light of the new 'bidding' regime wherein distributors must bid for power from generators, gas will be accepted if it is not outbid by competing fuels. In terms of costs of operation and lag times to completion, gas-based plants are easier to finance. As large power plants are capital intensive, the role of debt is important, and they need to be backed by long term Power Purchase Agreements (PPAs), which are a condition for financial viability. Provisions for third party access under the Electricity Act make it possible for a merchant plant to be set up without a long term PPA, which is an advantage for gas-fired generation.

The National Tariff Policy requires long term power purchases to be contracted only through the bidding process. Gas-based plants are, however, unable to win price bids, and in the absence of PPAs, can only come up in small sizes on the balance sheets of promoters. Thus, the market for gas-based power exists in the 'non-biddable' sections of the power market. Electricity demand by the latter has thus far even supported generation based on high priced spot LNG. However, as regards long term PPAs, domestic gas and LNG-based power face competition from coal-based power.

A tentative estimate for the cost of gas-fired power suggests that the fixed cost for a plant of medium capacity[78] is likely to be in the range of Re 1.00 – Rs 1.25 per kWh; and, for every increment of 1 US$ per mmbtu, the variable cost is approximately Re 0.35 per kWh. Although the price of D-6 gas at landfall point has been fixed at US$ 4.2 per mmbtu, after adding transport charges and other margins, the final price to users varies across states, from US$ 5.34 per mmbtu (in Andhra Pradesh) to US$ 6.21 per mmbtu (along the HVJ pipeline). This translates into an electricity generation price ranging between Rs 2.90 and Rs 3.40 per kWh (net of tax on gas). Table 22 shows the cost of power generated from coal and gas.

[78] Around 200 MW.

Table 22: Cost of Generating Power from Different Fuels

Fuel	Cost of Power (Rs/kWh)
LNG	5.00
NELP Gas	2.90 – 3.40
Domestic Coal	2.00 – 2.34
Imported Coal	2.70 – 2.90

Source: Compiled by authors.

Note: The numbers above are meant to be indicative, and are based on tentative guidelines laid out by the Prime Minister's Economic Advisory Council.

Table 22 indicates that power based on the approved price of domestic gas is within a 15–20 per cent range of domestic coal, and in some cases is cheaper than imported coal. Gas may therefore be competitive in peak load generation, in niche 'non-biddable' market sectors (merchant and captive plants) and traded electricity. However, it is currently unable to compete with coal on a larger scale, and only in the non-industrial sectors of the market for electricity.

Two broad conclusions can be drawn from the above analysis. First, the segments within which gas is potentially competitive at higher prices are the segments that can support such prices. These primarily consist of industrial consumers that opt out from the state grid and turn to power from captive generation. As long as the power deficit persists, the demand for gas from this segment is likely to increase. Second, the longer term market for gas in power generation, relative to coal, depends on factors not directly related to pricing. These include the manner and pace of power sector reform in Indian states. They also include external factors which support the role of gas as an intermittent fuel. There currently exists a debate in India over environmentally sustainable economic growth, coal dependency, and extending access to modern commercial energy to the large majority of the population that lack it. Countries such as the United Kingdom, whilst moving towards renewable (primarily wind) energy, have retained gas as a back-up option to deal with intermittencies in wind. The direction of the debate in India is likely to influence the future of gas in power generation.

6.4 Pricing in the City Gas Sector

City gas licensees receive gas from three sources; APM gas at subsidised prices (increased to US$ 4.2 per mmbtu in 2010), LNG at market prices, and most recently, NELP D-6 gas. The price charged by distributors varies across different uses or sectors. City gas comprises four consuming sectors: transport, household, commercial, and industry. The domestic Piped Natural Gas (PNG) price has so far been indexed to the administered retail selling price of a domestic LPG (14.2 Kg) cylinder, based on the heating values of natural gas and LPG. For small commercial consumers, the

price is indexed to commercial LPG, which is not subsidised. For large commercial consumers, the price is indexed to Light Diesel Oil (LDO) and bulk LPG prices, with different prices for consumers according to the quantity consumed. The transport sector is discussed later. Table 23 shows prices in the city gas sector in December 2010, for New Delhi and Mumbai.

Table 23: Price of Compressed/Piped Natural Gas by Consumer Sector

Consumer sector	Unit	Delhi	Mumbai
Automotive sector	**Rs./Kg**	29	31.47
Domestic sector	**Rs./scm**	18.95 plus 5% VAT	17.74
Small commercial	**Rs./scm**	33.33 plus 5% VAT	24 plus 5% VAT
Large commercial	**Rs./scm**	33.33 plus 5% VAT (for consumption above 2100 scm/day)	24 plus 12.5%VAT
Industrial sector	**Rs./scm**	24.75 plus 5% VAT	17.78 plus12.5% VAT

Source: Compiled by Authors

As the household and transport sectors are amongst the first recipients of domestic gas (in the gas utilisation policy), we investigate the relative prices of competing fuels in these two categories.

A comparison of the price of LPG (used primarily by households) and PNG reveals that at the subsidised consumer price of LPG, natural gas priced at Rs 19.90 per scm (inclusive of 5 per cent VAT) is viable. Table 24 compares the price of LPG and PNG on equivalent weight terms. The consumer price of LPG, at the *subsidised* level of Rs. 345 for a cylinder of 14.2 Kg (New Delhi) is roughly 8 per cent cheaper than the delivered price of piped natural gas in terms of calories.

Table 24: Price Comparison of Piped Natural Gas and Liquefied Petroleum Gas in the Household Sector

New Delhi Price	PNG	LPG
LPG Cylinder cost for 14.2 kg	-	345
PNG– Rs/SCM	19.90	-
PNG/LPG – Rs/Kg	26.18	24.29

Source: Compiled by authors

Substituting PNG for LPG in the household sector leads to additional costs of roughly Rs 2 per kg in equivalent terms. However, there is a case for substitution based on opportunity costs, relating to environmental externalities, costs of delivery, and amount of subsidy.

In the transport sector, petrol and diesel fuelled vehicles are much more expensive on a running cost per kilometre basis, than CNG fuelled vehicles. Table 25 shows the running cost for different kinds of vehicles by fuel type.

Table 25: Fuel Cost Comparison in the Transport Sector

	CNG	Petrol	Diesel
Price Rs/litre or Kg in Rs	29.00	58.38	37.71
Average Km/litre or Kg			
Car	21	15	-
Auto–rickshaw	25	35	-
Bus	3.5	-	3.5
Fuel Cost – Rs/Km			
Car	1.38	3.89	-
Auto–rickshaw	1.16	1.67	-
Bus	8.28	-	10.77

Note: Based on retail prices in Delhi
Source: Compiled by Authors

Table 25 shows that on a price per unit basis, CNG is a competitive fuel substitute. Although the prices of petrol are benchmarked to international prices, diesel is subsidised if the oil price crosses a predetermined ceiling (this has been US$ 83 per barrel but may be revised). Incentives are needed to encourage the adoption of CNG in transport. In Section 4, 'demand' projections suggested that the city gas sector will require 15.83 mmscmd of gas by 2012.

The analysis of pricing leads to two main conclusions. First, a comparative analysis shows that the price of gas as a fuel substitute in the main gas consuming sectors, although relatively high, still lies within a small percentage band of the prices of other competing fuels. This indicates that given certain external changes, such as an increase in the opportunity costs of using other fuels, there is, potentially, a major role for gas in energy use. Second, the distributional objectives within gas consuming sectors need to be met using a different mechanism to that of subsidising inputs in order to provide low-priced outputs to the poor, which eventually ends up benefiting the rich as well. This may require reviewing the policy objectives *within* gas consuming sectors, such as fertilisers, as we have discussed in this section.

7. Conclusions

The transition taking place in the gas sector in India is part of the larger movement of the economy from a centrally planned and administered system to one based on the operation of market principles. During transition, the situation is bound to be complex, and cannot be understood simply in terms of the conventional paradigm of demand and supply being brought into balance by price. Demand and supply are influenced by different factors but have, nevertheless, been kept broadly in balance by a complex system of administered pricing and quantitative allocation. The distortions have been spread across the gas consuming sectors, notably in sectors such as power and fertilisers, and have also affected the development of domestic supply as well as infrastructure – such as pipelines. The background to this system and how it has been changing is set out in Sections 1, 2, and 3. We would argue, however, that there is a logic to such transitions. As distortions mount, parts of the system are modified, usually in the broad direction of liberalisation and reform. But partial reform often has the effect of displacing the problems, for example from upstream to the consuming sectors, presenting new policy challenges, requiring further changes – and so on. The current situation, we suggest, is a 'half way house' – a stage on the way. But we are also optimistic. Much has already changed, and the momentum towards further changes is strong. This is the 'big story' referred to in the Introduction.

Why has the process of reform been so difficult in the gas and gas-related sectors? Why cannot gas in India just be liberalised – handed over to the market? After all, as noted in this paper, liberalisation and marketisation have gone much further in the case of oil – so what is special about gas? We suggest that there are two reasons. The first is simply infrastructure. Even in a fully marketised economy, infrastructure (such as the system of gas pipelines) requires regulation and coordination – in a word, 'planning'. Liberalisation requires institutions of the appropriate kind.

The second is both more important, and more difficult. Gas in India is mostly used in fertiliser production and in power generation. India has a long tradition of providing basic goods to the poorer sections of society at highly subsidised and controlled prices. Within the state sector, much of this subsidy has been provided by allocating low-priced gas to the producers of fertiliser (mostly urea) and electric power. These producers pass on their low-priced outputs to the final consumers – especially in the agricultural/rural sector of the Indian economy. Thus gas pricing and allocation has been intertwined with some of the most important and challenging distributional objectives of Indian development strategy. Large changes in the pricing and allocation of gas cannot occur without finding other ways of addressing distributional and agricultural objectives. Needless to say,

the issues of reform, distribution, and poverty alleviation are central to many other sectors of the Indian economy. They are particularly obvious, however, in the case of gas.

It is worth taking a brief sideways glance at what has been happening in the oil sector. Again, there is a long history of controlling and subsidising oil products, which has led to distortions – particularly when the international price rose rapidly in the period 2005–08 (70 per cent of Indian oil is imported). With controlled prices for the consumers, losses mounted in the state-owned marketing companies, as well as amongst domestic oil producers such as ONGC. In this case, however, there has been considerable liberalisation, with most oil and oil products now trading at market prices. The distributional issues were highly salient in the debates, with opponents arguing that the poor would suffer from higher prices. This, however, is a very poor argument since subsidies on oil products such as petrol are known to be highly regressive – with the largest benefit going to the rich. In the event, the forces making for reform prevailed. But along with this strategy, poorer sections of the population were targeted, for example by continuing to control and subsidise kerosene. Diesel prices were also controlled (and subsidised) for oil prices over US$ 83 per barrel.

In the case of gas there are, in fact, various issues in the different sectors of the overall market. For town gas, a relative newcomer, the underlying situation is broadly similar to that for oil. Prices are broadly market determined, and there is little pressure for town gas to be supplied at low prices to meet distributional objectives. LPG, however, has been subsidised for distributional reasons. In early 2011, policy has moved towards further targeting on the poor, using the system based on Unique Personal Identification Numbers.[79] Industrial and commercial gas users (excluding the power and fertiliser sectors) mostly already pay commercial prices for gas.

The most difficult sector of gas usage is fertilisers, principally the production of urea. We have noted the long history of subsidising this key agricultural input via low gas prices – and the political salience of this basic commodity. For this sector the key is not the removal of subsidies, but changes in the subsidy regime to a less economically damaging and more efficient system. With the recent rise in gas prices to US$ 4.2 per mmbtu, much of the highly distorting subsidy on the input of gas has been removed. We have suggested that this change in policy has not gone far enough, and that one of the consequences has been the continuation and revival of the gas utilisation policy. The gas utilisation policy is both a hangover from the past, and necessary in the present to ration relatively low-priced gas. However, the major change in the gas price has (inevitably, we would argue) been accompanied by a change in the subsidy regime. The implicit subsidy, via under-

[79] This is a technology which is being developed in India to 'identify' citizens for purposes such as targeting of subsidy and development programmes. The first phase of this programme was launched in 2011.

recovery and losses in the state-owned sectors, became untenable. It has been replaced by explicit subsidies to the price of fertiliser via the Federal budget – a much less distorting and more transparent system. This is unlikely to be the end of the process. The government has already signalled its intention to further target the subsidy on the users of fertilisers, especially poor farmers.

The other great user of gas is the power generation sector where, however, gas accounts for a relatively small proportion (around 10 per cent) of generation capacity. Superficially, the story in this sector is similar to that in fertilisers; the sector has depended on allocated gas provided at low prices. But, unlike in the case of fertilisers, the distributional argument for providing cheap gas is very weak, not least because of its relatively small contribution to overall power generation. To be sure, the distributional issues are central to the power sector, which has been responsible for the extension of electricity supply to rural areas at low prices. As shown in this paper, the rural subsidy has essentially been financed by cross subsidisation (as well as by losses in many of the state distribution utilities). These issues go well beyond the scope of this paper. But, it is hard to make a case for subsidised gas in power, purely on distributional grounds. It is also evident that the distributional objectives in power have had their most important effects via the pricing and allocation of coal, and the distortions that exist in that sector.

The objectives for using subsidised gas in power are therefore likely to be different. They could be related to India's increasingly visible climate agenda, and there may indeed be a role for gas in power in the longer-term, especially in relation to India's objective of increasing the share of gas and renewables in power generation by the year 2022. However, using subsidised gas in power to meet this objective is subject to the same inefficiencies discussed earlier. One way to encourage the use of gas in power, without subsidising it, is to instead put a tax on coal. This would, however, open up more issues – it would raise the electricity price for all consumers – leading to the question of how the distributional issue that comes with this increase should then be dealt with. This is an illustration of the nature of gas reforms, and indeed of energy reforms in general, in that they cannot be considered in isolation from other energy and economic sectors. It highlights the need in India for a formal integrated energy policy, which is beyond the scope of this paper, but requires further research.

Although we have evaluated current policy on gas, as it stands, the situation in the gas sector is uncertain. What then needs to be done to ensure that this uncertainty is resolved, and that things begin to move in a positive direction? Based on the findings of this paper, we set out some recommendations.

The Way Forward: Supply Issues

As explained in this paper, the pressure for 'reform' in the gas sector has undoubtedly come from the supply side of the picture. The National Oil Companies were seen to have failed to develop the hydrocarbon sector as effectively and as quickly as policy makers desired. In both oil and gas, a key element was the pricing of oil and gas – and the natural benchmark (especially for oil, given the extent of imports) was the international price. We have pointed out how the price of gas for producers requires more clarity and definition; the price of US$ 4.2 per mmbtu was based on the very first 'price discovery' process that was eventually similar to a contractual negotiation. It is based on a general set of 'guidelines' highlighted by a ministerial Committee, but no formal long-term government policy or position on the price system exists. Thus, we know that producer prices will be revised in 2014, but it is unclear on what basis. However, as the paper shows, the current system is a result of the contractual provisions within the NELP fiscal regime.

Although there has been much debate on the price paid to producers, the unlocking of potential supply therefore also depends crucially on the fiscal terms, as seen earlier in this paper. The NELP regime was intended to open up exploration and development, but did not fully achieve its objective.

Under NELP, a major concern is that acreages that are auctioned are not then brought into production quickly enough. The fiscal terms for the development of acreages – particularly the relinquishment norms and the commitment to drill a certain minimum number of exploratory wells per 'block' within a minimum period – need to be tightened up. Another key concern is with the tax and profit sharing regime, which has discouraged international exploration companies from bringing in much needed capital and technology. Companies with businesses in India are allowed to offset losses from exploration against these other businesses – an advantage not available to international companies. Also, public sector companies are able to win acreages based on their generous, but in most cases unrealistic, profit-sharing offers. These factors have contributed to a glut in the number of acreages being auctioned, but not yet developed, and therefore also to the lack of essential geological data.

Arguably, one part of this supply side 'story' has already been played out, with the increase in the price of APM gas to US$ 4.2 per mmbtu in 2010. It could be argued that this increase was inevitable; first, state-owned companies could not indefinitely continue making losses on underpriced gas as this was unsustainable; second, as this paper has shown, APM gas production

has been declining, while the quantity of gas that is not under the APM system is increasing; and third, there were a large number of potential offshore discoveries which simply could not be ignored – the need to encourage exploration and development meant that it was a necessary signal to potential investors who could provide the capital to bring these discoveries into production.

The second area of policy attention on the supply side relates to infrastructure. As private companies are permitted to invest in pipelines, the concern here is not that infrastructure will not develop; recent events have shown that private companies such as Reliance have willingly invested in building pipeline networks. The concern here is about regulatory issues, and there is need for formal clarity on the definition and functions of an independent regulator (potentially, the Petroleum and Natural Gas Regulatory Board) for pipelines, and guidelines on an 'arm's length' relationship and universal service obligations in pipeline construction and operation. The issue of regulation is in itself a separate subject that deserves more research and analysis, which is beyond the scope of this paper.

Demand Issues

Although demand implicitly depends on the unlocking of potential supply, the main issue in demand is really about the price of gas sold to consumers within India. There is presently, as we have seen, a mixed system for gas pricing. This requires consolidation, on a commercially-sound basis. From international experience, it is possible to introduce a new, reformed pricing system alongside an older system, with the eventual goal of prices converging to international levels. However, this is easiest to do in sectors where there is the least political resistance.

The 'right' price for gas would be one that fits best with India's evolving long-term objectives, and depends on whether gas should play a bigger role in the future. In this paper, we have identified a role for gas in the main consuming sectors, based on its competitiveness with other fuels, to varying extents.

In the power sector, there are some instances where gas may be competitive with coal in generation. Although coal has tended to have the lowest cost of production, coal imports have been increasing (as shown earlier in Table 3). Electricity produced with domestic gas is competitive (within a broad range) with electricity produced from imported coal (Table 22), and the marginal cost of coal is increasingly given by imports. Coal freight tends to increase with the distance from the mine; it therefore ranges between US$ 4 and US$ 30 per tonne between a range of 200 km and 2000 km from the pit head (*Report of the Expert Committee on Fuels for Power Generation*, 2004). Thus, costs are higher on the west coast, which is also where the main centres of demand are located, as

compared to the east coast and north-eastern states, which is where coal mines are concentrated. Although gas at higher prices may be viable in some user segments, mainly captive and merchant generation, it is based on system failures elsewhere. This is, at best, a short-term justification for an expanding demand for gas. However, looking further forward, there is a potentially greater role for gas, based on future policy orientations, as discussed earlier in this section.

In city gas, our analysis found that gas (CNG) is a viable substitute in the transport sector and, based on opportunity costs, gas (PNG) could also be a viable alternative to LPG in the household sector.

In the fertilisers sector, there is a greater role for gas, and there has been reform – the new Investment Policy links the price of urea, the main fertiliser product, produced by new manufacturing plants, to the price of NELP KG-D6 gas, which is to be revised every five years. It also mandates the conversion to gas of all naphtha-based urea manufacturing plants by 2012. As argued earlier, the potential future role of gas in fertilisers appears to be the most 'certain'. However, the distributional objective in gas is also seen as most relevant in the fertiliser sector, rather than in power (where, as we have seen, gas is competitive in certain consumer segments even at higher prices) and city gas (which thus far has not contained the same levels of distortion as in other gas consuming sectors).Total central government expenditure on subsidies to fertilisers in 2010–11 amounted to roughly 4.5 per cent of total government expenditure and 0.7 per cent of GDP, at current market prices.

A policy recommendation on the demand side would therefore be to draw on the experience in the oil sector, and subsidise the output, rather than the input, where necessary. Thus, effectively liberalising prices in the gas sector, but providing a direct subsidy to fertilisers. The use of direct subsidies is, in effect, already being considered in the fertilisers sector. But reform must not end here.

The recent announcement on direct subsidies to fertilisers is a key policy measure, and a better method compared with the system that existed before, as it introduces some transparency. However, it is arguably a short-term solution, and does not altogether resolve the problems that exist. In the medium term, policymakers need to also consider reviewing the self-sufficiency objective in addressing the distortions *within* fertiliser use. The large differential between cost of production and retail price indicates the extent of under-pricing that exists as a result of current policy objectives (Section 6, Box 2). This is also evident in the inefficient use of urea in crop cultivation.

Events on the demand side also depend on the future role of the allocation mechanism. This mechanism, to a large extent, serves to ration subsidised gas. Even with the increase in prices to US$ 4.2 per mmbtu, there is still likely to be excess demand. Imported gas is more expensive, but the main consuming sectors do not have to depend on it, as they are allocated lower-priced gas. The diagnosis of excess demand is supported by the fact that there has been demand for LNG even at the higher long-term contracted prices. If domestic gas prices were to be raised to a higher level to choke off excess demand (the precise identification of how much they would need to rise requires more research), or if they were freed, one could argue that the gas utilisation policy would start to become redundant, particularly if the distributional objectives are met in a more direct manner, such as the direct provision of subsidies to the end user.

Looking Ahead

There is an urgent need for Indian policymakers to draw on market oriented solutions to resolve the immense uncertainty that exists in the gas sector. The policy measures announced in 2010, and in Budget 2011, are steps towards this; additionally, the recent deregulation of prices in the oil sector are an illustration of the fact that the government may not intend to stop its progression with reforms on gas.

In short, in the 'bigger' story, the current situation in the gas sector is arguably better than what it was before 2010; however, it also presents new and more urgent challenges. The transition must continue, in order to ensure that India moves forward from its current 'half way house' position.

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Appendix I: LNG Terminals and Gas Pipelines in India

Source: Gas Authority of India Limited
Note: The TAPI Pipeline is a planned and not an existing pipeline.