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Study on Common Pool Price Mechanism for Natural Gas in the country

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STUDY ON COMMON POOL PRICE MECHANISM FOR NATURAL GAS IN THE COUNTRY

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ABBREVIATIONS

APM	**Administered Price Mechanism**
CERC	**Central Electricity Regulatory Commission**
CGD	**City Gas Distribution**
CNG	**Compressed Natural Gas**
DC	**Designated Consumers**
LNG	**Liquefied Natural Gas**
MMSCMD	**Million Metric Standard Cubic Meter per Day**
TCM	**Trillion cubic meters**
MMBTU	**Million Metric British Thermal Units**
MMTPA	**Million metric tons per annum**
MoPNG	**Ministry of Petroleum and Natural Gas**
MSCM	**Thousand standard cubic meter**
PMT	**Panna Mukta Tapti**
PNGRB	**Petroleum and Natural Gas Regulatory Board**
Px	**Power Exchange**
R-LNG	**Regasified Liquefied Natural Gas**
RTC	**Round the clock**
UI	**Unscheduled Interchange**
OTC	**Over the counter**
OCM	**On the commodity market**
PSC	**Production Sharing Contracts**
TSO	**Transmission system operator**

EXECUTIVE SUMMARY

The natural gas markets in India are developing rapidly. Over the past decade the volumes have gone up significantly with commencement of NELP gas production, followed by introduction of term LNG and finally with the supplies from RIL's KG D6 gas fields. In a short span of time the gas supply volumes in the country have tripled.

Yet the demand for natural gas has been growing and continuing to grow at an unrelenting pace. From the current share of 10% of the energy basket of the country, it is anticipated to grow to about 25% by 2025. The demand comes from a variety of consuming sectors. However power and fertiliser would require the maximum amount of gas in quantitative terms. Even as industrial and city gas demand grows rapidly, we anticipate that about 70-75 percent of the new demand originating from the power and fertiliser sectors.

However both of these sectors are sensitive to price volatility. Power tariffs are either controlled or regulated within a price band and fertiliser units are provided a subsidy to assure a fixed unit-output price. Government is a major customer, as a subsidy provider and a significant distributor of power. As domestic gas (based on identified finds) would not be adequate to meet their rapidly growing requirements, there would be a need for introducing new gas sources. In particular, considering the geopolitical situation in the region, the complex agreements and guarantees necessary to underwrite and secure transnational gas pipelines, the Indian market has grown to favour LNG as a more flexible and practical source for gas imports, through a mix of term contracts and spot deals. Imports will be a significant component of the fuel and feedstock price basket for new power and fertilizer customers, and these two sectors will continue to anchor the growth of a country gas grid. There is a symbiotic relationship between anchor customers underpinning gas grid growth and smaller new consumers who are less sensitive to input fuel and feedstock prices simply due to their better control over determining prices of their own product-output.

The prices of LNG in the Asia Pacific basin are generally linked to crude oil. This results in very substantial volatility in the prices, and also in general higher price levels as compared to the existing natural gas supply basket. As such it is extremely difficult for price sensitive consuming industries to plan operations purely based on LNG from future sources. However, in the light of the urgent energy needs of the country, it is important to consider alternate arrangements that permit new supplies to be brought in without compromising interest of consumers, particularly that of anchor customers. Pooling arrangements allow for these objectives to be met. The need and benefits of pooling for the Indian gas markets need to be considered in the context of the market development objectives. These could be summarised as follows:

1. Introducing new gas sources in the market;
2. Ensuring stable price signals for long gestation investments based on gas;
3. Deepening the pipeline network to expand the gas markets geographically;
4. Sending appropriate price signals for efficient use of gas;

As of today, different prices of natural gas prevailing in the country can be put broadly under three categories. Till the KG D-6 gas production commenced, out of the total gas being supplied, almost 40% was based on Administered Pricing Mechanism (APM). Even in case of APM gas, there are different prices prevailing for priority sector (power & fertiliser), North Eastern region (North Eastern power & fertiliser) and non priority sectors. To add to complexity, seven more types of prices are prevalent for gas coming out of production sharing contracts—be it from PMT, RAVVA, KG basin or other fields. The third category is LNG, which is broadly available at prices based on buyer-seller contracts.

Under the circumstances, a single benchmarked price of natural gas in India would be in the larger interest of the consumers, and also benefit the market development of natural gas in this country.

The study considered several pooling options and shortlisted the following as some of the more practical variants:

Option A: A general cost based pool covering all consuming sectors and all suppliers, excluding those of spot LNG. The option would become operational only through a legislative mandate since the provisions of existing PSCs relating to price discovery would be affected; Changes in PSC terms may have ramifications on the fiscal stability that upstream companies desire to defray returns risk, and its effect may be more severe on small exploration companies that are active in India, and which need stable PSC terms to attract larger partners to develop and monetise new gas finds.

Option B: A more limited sectoral pool arrangement covering the price sensitive power and fertiliser sectors, which are heavily subsidised as well as subjected to heavy regulations. Even as the pools would be smaller than a comprehensive pool, it would still be large enough to contain volatility to a certain measure and also introduce new supplies within the limits established by the pool governance rules. Power and fertiliser due to their reasonably large unit gas demand are also good anchor customers for new locations around which to grow the pipeline network. A growing grid supports smaller consumers who are less price sensitive and can support out-of-pool import contracts, smaller domestic gas sources and spot LNG.

Option C: Competitive markets based on auction pools (bid based pools) on the lines already established for the power sector in the country. Even as this would be superior in many respects, we believe that the network infrastructure would need to be in place on a much larger scale than at present to ensure that the market can function. We believe that over the next 3-4 years this should be possible, and should be considered for introduction at that stage.

All aspects considered, we believe that the sectoral pool option would be most suited at this stage. It would serve the basic objectives without being heavy on administrative arrangements and costs. It would also be facilitative of an eventual migration to competitive markets. It needs to be noted that a cost based pool or long term contracts could co-exist with competitive gas markets. We also believe that the sectoral pool option would leave sufficient room for price discovery for new gas supplies.

Even as the sectoral pool would be relatively simple in terms of administration, it would still require substantial preparatory work for its introduction. Our review suggests that legislative changes would not be required to modify PSC terms. Instead a sectoral pool could work through a simpler policy directive. The policy would need to set out the detailed guidelines for constitution and operations of the pool, notify a pool operator, set out the institutional mechanisms, and also the transition processes. This report outlines certain key measures in this regard.

We have reviewed international practices regarding pooling, and there are few parallels to India. Several developed countries have migrated to competitive markets (US, UK), while other operate on a cost pooling by dominant national gas sector operator(s) (e.g., ENI in Italy, GDF in France). Some of the countries have both arrangements operating in parallel. In some of the large markets in the developing world (e.g. China), the suppliers are generally the aggregators of contracts and sell at a pooled price. India is in a transition phase, and eventually with the introduction of new supplies can emerge as one of the largest gas markets, with key despatch/aggregation points emerging as gas hubs. We believe that the proposed sectoral pooling arrangements would advance India's development into a large gas market. Our analysis also reveals that within limits set out on the pool prices, it would be possible to introduce a significant amount of gas imports into the Indian gas basket, without causing major perturbations in the user industries. We also believe that pooling would help rapid expansion of the gas transmission network into unserved parts of the country.

Our terms of reference require us to analyse the possibility of pooling of transportation tariffs. We have examined the issue, but have found it to be inefficient and distortionary. It can also result in stranded assets that would prevent efficient gas market development. Instead we favour the idea of co-ordinated pipeline development across the country, and charging of tariffs for pipeline use on a rational economic basis. If required, in the development period, the revenue deficits can be made good through a time-defined access deficit charge implemented for supplies in developed regions.

Finally, we recommend the creation of a roadmap for migration to competitive wholesale markets for gas, which would typically be through bid based pools, and feature a large number of independent shippers. We believe that this will lead to eventual reduction in the price of gas imports by India, and aid the process of the country becoming a major player in the international gas market.

I OBJECTIVE OF THE STUDY

As a commodity, natural gas is increasingly in demand in India. Natural gas presently constitutes about 10% of the country's energy basket. India's hydrocarbon vision statement envisages the share of natural gas to be about 25% by 2025. With a substantial increase of share of natural gas on a rapidly increasing energy consumption base, it becomes imperative to identify new gas sourcing options, creating mechanisms for the markets to absorb the gas, and rationalising the pricing mechanisms in order to encourage efficient consumption as well as efficient and adequate souring of the commodity.

Natural gas pricing in India is diverse and complex in nature. India is one of the few countries where different types of basic prices of gas are prevalent. Across the gas value chain and particularly for consumers, the complexity in the pricing of natural gas in India has resulted in enormous problems. Consumers have been subjected to unfair situations because they buy their requirement of natural gas at different prices and finally complete for their finished products in the open market.

Worldwide, single uniform benchmark price is the prevailing practice in different countries like the US (Henry Hub), the UK (National Balancing Point) and Europe. In a country where the natural gas market is still in its nascent stage it is worth evaluating the benefits of a single benchmark price for natural gas.

Historically, the pricing of gas in India has witnessed three distinct eras. Prior to 1987, it was a negotiated price broadly guided by replacement of alternative fuel, linkage being mainly with coal. In the same year the first structured pricing order on cost plus basis was issued. Subsequent to pricing orders by Kelkar Committee (1991), Shankar Committee (1997) and finally by the government in 2005, the idea of a market-driven price evolved. The second era in pricing could be linked to prices based on Production Sharing Contracts (PSC) which came as a consequence to the New Exploration and Licensing Policy (NELP). Prices emerging out of buyer-seller contracts for LNG saw the third pricing regime. However, the price of LNG in the international market fluctuated a lot and in order to protect the customers, particularly the power plants—the government arrived at pooled prices for a certain period.

As of today, different prices of natural gas prevailing in the country can be put broadly under three categories. Till the KG D-6 gas production commenced, out of the total gas being supplied, almost 40% was based on Administered Pricing Mechanism (APM). Even in case of APM gas, there are different prices prevailing for priority sector (power & fertiliser), North Eastern region (North Eastern power & fertiliser) and non priority sectors. To add to complexity, seven more types of prices are prevalent for gas coming out of production sharing contracts—be it from PMT, RAVVA, KG basin or other fields. The third category is LNG, which is broadly available at prices based on buyer-seller contracts.

Under the circumstances, pooled price of natural gas in India may be in the larger interest of the consumers, and also benefit the market development of natural gas in this country. Power and fertilizer constitutes approximately 62% of the total demand for natural gas in the country. Attaining a single benchmark price for natural gas will bring stability in the varying gas price which in turn will bring stability across various projects.

In the future, a large upsurge in gas demand is foreseen to meet the unmet and latent demand, as well as the future energy needs. Gas is necessary not only a clean fuel, but also will make up for the significant shortfalls between demand and supply of energy in the country.

To summarise, the following are the key objectives of a gas price pooling mechanism in India would be as follows:

- To achieve price stability
- To encourage broadening of gas supplies in the country
- To develop natural gas market in the country

These would in turn provide a clear reference for long gestation project to plan their investments and also to provide for mitigation of some of the key risks. This study reviews the various options on gas pooling in detail and concludes on the preferred mechanisms for the present, keeping in view the development of the gas supply and pricing infrastructure, past history of pricing, and the immediate policy priorities. The report also identifies the roadmap for future development of competitive gas markets in the country.

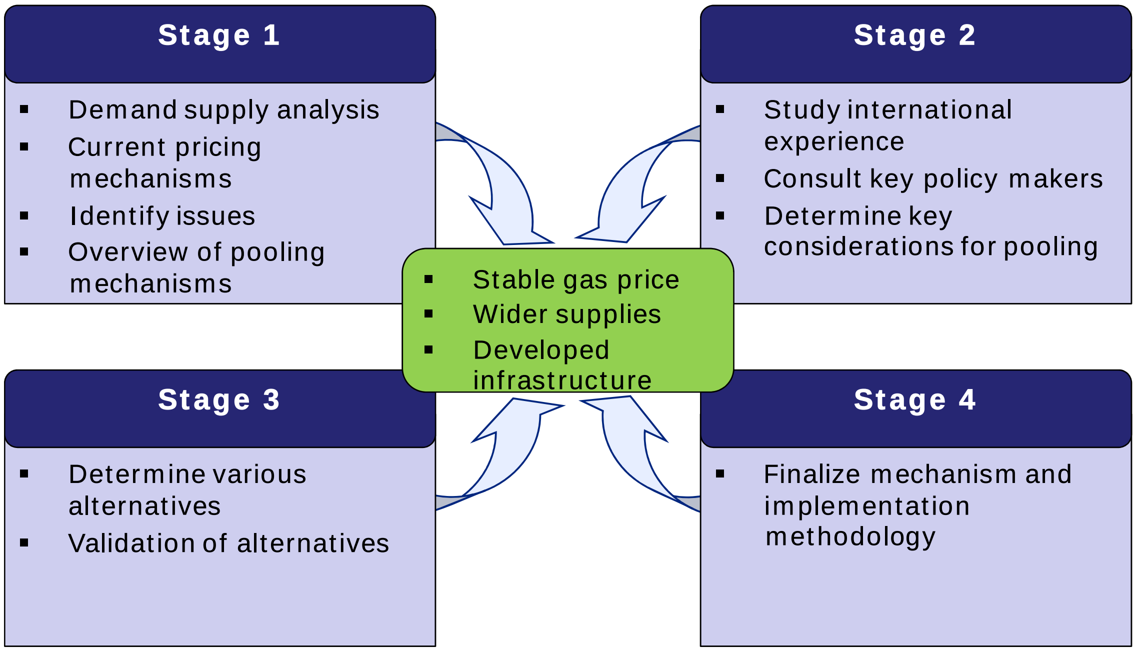
The report is organised as follows:

- Chapter II identifies the approach and methodology
- Chapter III discusses in detail the characteristics of the natural gas market in India
- Chapter IV discusses the current gas pricing methodologies
- Chapter V elaborates on the need for pooling
- Chapter VI identifies the pooling mechanisms studied as part of the study
- Chapter VII discusses international gas pricing systems based on select regions and countries reviewed
- Chapter VIII deliberates on the transportation tariff pooling issues

The report concludes with the Consultant's recommendations in Chapter IX.

II BROAD APPROACH AND METHODOLOGY

The following figures highlights the broad approach and methodology adopted for the conducting the study.



The activities conducted in each stage are described below:

Stage 1: In stage 1, the demand supply gas balance for the future years was identified. The future demand in case of power was identified based on the Government of India plans and also the latent demand that may arise due to shortage of coal. The current pricing system for natural gas and issues therein were also identified.

Stage 2: The second stage involved the study of the practices adopted in various countries/continents like USA, UK, Italy, Continental Europe etc. This stage also involved discussion with the key policy makers and determining the key considerations for pooling.

Stage 3: This stage involved determining various alternatives and thereafter validation and applicability of these alternatives.

Stage 4: In stage 4, the most tenable mechanism has been identified and the implementation methodology was assessed. Extensive consultation was undertaken with MoPNG and GAIL officials to determine the most practical mechanisms, as well as future pooling and market frameworks.

The outcome of the study based on the methodology outlined above is reflected in the recommendations provided in this report.

III INTRODUCTION TO THE INDIAN NATURAL GAS MARKET

1. DEVELOPMENT OF THE NATURAL GAS MARKETS IN INDIA

India is the world's seventh largest energy producer, accounting for 2.49% of the world's total annual energy production. It is the fifth largest energy consumer, accounting for about 3.45% of total energy consumption in 2004, which has been increasing by an average of 4.8% percent a year since 1990. The share of commercial energy in total primary energy consumption increased from 59.7% in 1980-81 to 79.3% in 2008-09.

India's GDP has grown at more than 8-8.5% during the last few years, and is expected to grow at least at 6.5-7% in the coming few years. The growth has taken place despite the huge deficit in energy infrastructure and infrastructure. Even today, half of the country's population does not have access to electricity or any other form of commercial energy, and still use non-commercial fuels such as firewood, crop residues end during cakes as a primary source of energy for cooking in over two-thirds of households. The future growth of the country would demand a move to large scale commercial energy forms. In particular, natural gas as a clean energy source holds the highest promise for the country.

World's resources of natural gas, although finite, are enormous. Estimates of its size continue to grow as a result of innovations in exploration and extraction techniques. Natural gas resources are widely and plentifully distributed around the globe. It is estimated that a significant amount of natural gas remains to be discovered. Natural gas has emerged as the most preferred fuel due to its inherent environmentally benign nature, greater efficiency and cost effectiveness.

The demand of natural gas has sharply increased in the last two decades at the global level. In India natural gas was first discovered off the west coast in 1970s, and today, it constitutes 10% of India's total energy consumption. Over the last decade it has gained importance as a source of energy and its share is slated to increase to about 25% of the total energy basket by 2025-2030.

2. PRODUCTION AND SUPPLY OF NATURAL GAS

Production of natural gas, which was almost negligible at the time of independence, is at present at the level of around 132.83 million standard cubic meters per day (MMSCMD). The main producers of natural gas are Oil & Natural Gas Corporation Ltd. (ONGC), Oil India Limited (OIL), JVs of Tapti, Panna-Mukta and Ravva and Reliance Industries Limited (RIL) which has discovered gas in the Krishna Godavari basin at its KG D6 block in the east cost of Andhra Pradesh.

Out of the total domestic production of 132.83 MMSCMD of gas about 43% is produced by Reliance Industries Ltd. (as of December 2009) and approximately 57% of the gas is produced by others. Table 3.1 provides the details of the production of natural gas in 2009-10 by Government & Private sector.

Apart from the KG D6 gas, the onshore fields in states of Assam, Andhra Pradesh and Gujarat are other major producers of gas. Smaller quantities of gas are also produced in states of Tripura, Tamil Nadu and Rajasthan. OIL is operating in states of Assam and Rajasthan, whereas ONGC is operating in the Western offshore fields along with other states. Gas produced by ONGC and a part of the gas produced by the JV consortiums is marketed by GAIL (India) Ltd. . Gas produced by OIL is marketed by OIL itself except in Rajasthan where GAIL is authorized to market its gas. Gas produced by Cairn Energy from Lakshmi fields in Gujarat and Gujarat State Petroleum Corporation Ltd. (GSPCL) from Hazira fields is being sold directly by them at market determined prices.

Table 3.1: Production of Natural gas (MMSCMD)

Source (2009-10 figures)	Volume (MMSCMD)
ONGC and Oil	**54.32**
***RIL KG D6**	**57.14**
PMT/ Rava/Rava Satellite	**18.67**
Long term RLNG	**21.69**
***Shell Spot**	**5.54**
***Petronet Spot**	**1.59**
Other gas	**2.70**

*December 2009 data

Source: MoPNG and GAIL

The current supply of natural gas is approximately 161.65 million Standard cubic meters per day (MMSCMD). The private sector entered natural gas production in 1998-99. During 2007-08, ONGC and OIL jointly accounted for about 76% of the total gas produced, while the remaining came from private players and JVs. The remaining gas supply has been through re-gasified liquefied natural gas (RLNG). LNG supply which during 2007-08 was about 8.25 Million Tonnes. Another new hydrocarbon resource, coal bed methane (CBM), commenced production July 2007. India's CBM reserves are estimated to be 4.6 trillion cubic meters (TCM). Great Eastern Energy Corporation Limited commenced commercial production of CBM in India at a rate of 100,000 SCMD, from its Raniganj (South) block in West Bengal.

3. SECTOR WISE NATURAL GAS DEMAND

Power generation and fertilizer industry are the major consumers for nearly two-thirds of consumption of natural gas in India. The industry-wise off-take trend of natural gas in India in million cubic meters for the period 1990-91 till 2007-08 is summarized in Table 3.2 below.

Table 3.2 : Industry-Wise Off for Natural Gas in India (MCM)

Segment	1995-96	2000-01	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Power Generation	6836	8801	10510	11478	12099	11878	11963	12037
Industrial Fuel	2301	2870	2939	3099	3569	3780	3205	3324
Tea Plantation	111	151	119	142	142	151	170	160
Domestic Fuel	178	335	654	93	343	75	443	39
Captive use/ LPG Shrinkage	589	5004	5409	4865	4944	5048	5034	5618
Others	0	38	136	1263	231	1120	40	1258
Total (A)	**10015**	**17199**	**19767**	**20940**	**21328**	**22052**	**20855**	**22436**
Fertilizer Industry	7602	8480	7955	7889	8173	7762	8497	9822
Petro-Chemicals	474	779	1027	1128	1236	1175	1377	1432
CNG				1				
Others		1402	1215	948	37	36	639	638
Total (B)	**8076**	**10661**	**10197**	**9966**	**9446**	**8973**	**10513**	**11892**
Grand Total (A+B)	**18091**	**27860**	**29964**	**30906**	**30774**	**31025**	**31368**	**34328**

Source: ONGC, OIL, DGH and GAIL. Excludes offtakes of natural gas by ONGC,

As per the working group report on petroleum and natural gas sector for the XI plan period the demand would grow to 279.43 MMSCMD in the year 2011-12. The following table highlights the demand estimated in the working group report.

Table 3.3 : Segment wise demand for natural gas (MMSCMD)

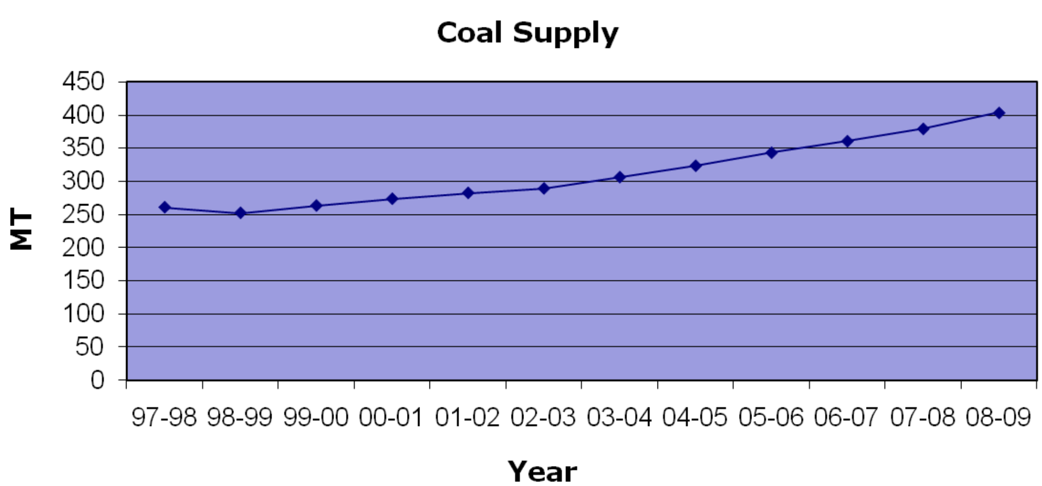
	2007-08	2008-09	2009-10	2010-11	2011-12
Power	79.70	91.20	102.70	114.20	126.57
Fertilizer	41.02	42.89	55.90	76.26	76.26
City Gas	12.08	12.93	13.83	14.80	15.83
Industrial	15.00	16.05	17.17	18.38	19.66
Petchem-Refinery	25.37	27.15	29.05	31.08	33.25
Sponge Iron	6.00	6.42	6.87	7.35	7.86
Total	179.17	196.64	225.52	262.07	279.43

Source: Working group report on petroleum and natural gas sector for the 11th plan period

4. NATURAL GAS BALANCE – NEXT FIVE YEARS

A detailed analysis based on the current and upcoming power plants and fertilizer plants has been done to estimate the demand for natural gas in the country. Power and fertilizer sector will continue to be the main segments consuming natural gas in coming years. The power and fertilizer sector together will consume around 76-80% of the total natural gas consumed in the country. There will be huge demand for natural gas on account of shortage in coal supplies.

Mercados EMI has undertaken a substantial review of the alternative fuel sources available in India, especially for the power sector which is the largest consumer of gas on a sectoral basis. At present the country largely relies on coal for its power generation. The coal availability in the country is severely limited on account of the issues related to environment, mining constraints, rehabilitation issues, etc. As a consequence of these factors the coal production growth in the country has been inadequate. The following chart identifies the past growth trajectory in coal production.



The average growth in production is 3.71 percent per annum. As compared to this in future the country would require a growth in coal supply at about 8 to 9 percent per annum. Even with captive coal mining and increased supply of imported coal, the gap is very large.

Natural gas provides a plausible alternative to coal. Gas as a clean and flexible fuel is much in demand. It is understood that in the XIIth Plan period the country is likely to aim for gas based capacity addition of 5000 MW per annum. This would correspondingly require an additional 100 MMSCMD of supply by the end of the XIIth Plan period.

Demand is also anticipated to grow substantially for fertiliser, industry and for city gas, all of which prefer gas over the existing options on account of environmental and economic factors.

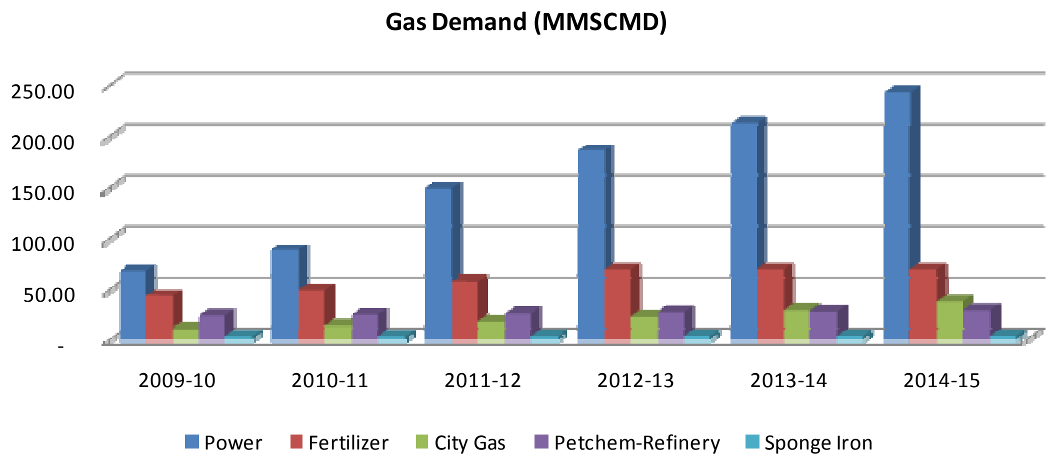
Considering the factors discussed, the following table highlights the demand of natural gas for different segments in the country. The plant wise break-up of the power and fertilizer capacities is provided in Annexure.

Table 3.4 : Segment wise estimation of demand for natural gas (MMSCMD)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	Basis
Power	66.42	87.71	149.11	185.52	212.73	243.34	Units planned
Fertilizer	42.93	49.39	57.48	68.08	68.08	68.08	Units planned
City Gas	10.70	13.70	17.53	22.44	28.72	36.76	Trend
Petchem-Refinery	23.50	24.44	25.42	26.43	27.49	28.59	Trend
Sponge Iron	3.60	3.71	3.82	3.93	4.05	4.17	Trend
Total	**147.15**	**178.94**	**253.36**	**306.41**	**341.08**	**380.95**	

Source: Mercados research

The following figures depict the increase in consumption pattern of natural gas across various segments. The demand in power sector is expected to grow at an average of 30%, whereas in fertilizer sector it is expected to grow at an average of 10%.



5. PIPELINE INFRASTRUCTURE

The present gas trunk pipeline grid is about 10,000 km in length. It supplies to 8 lakh households and 4 lakh CNG-vehicles in 25 cities located mainly in the northern and western parts of India. GAIL India, a public sector undertaking, owns more than 67% (6800 km) of the network followed by Reliance Industries Limited 14% (1400 km), Gujarat State Petronet Limited (GSPL) which owns

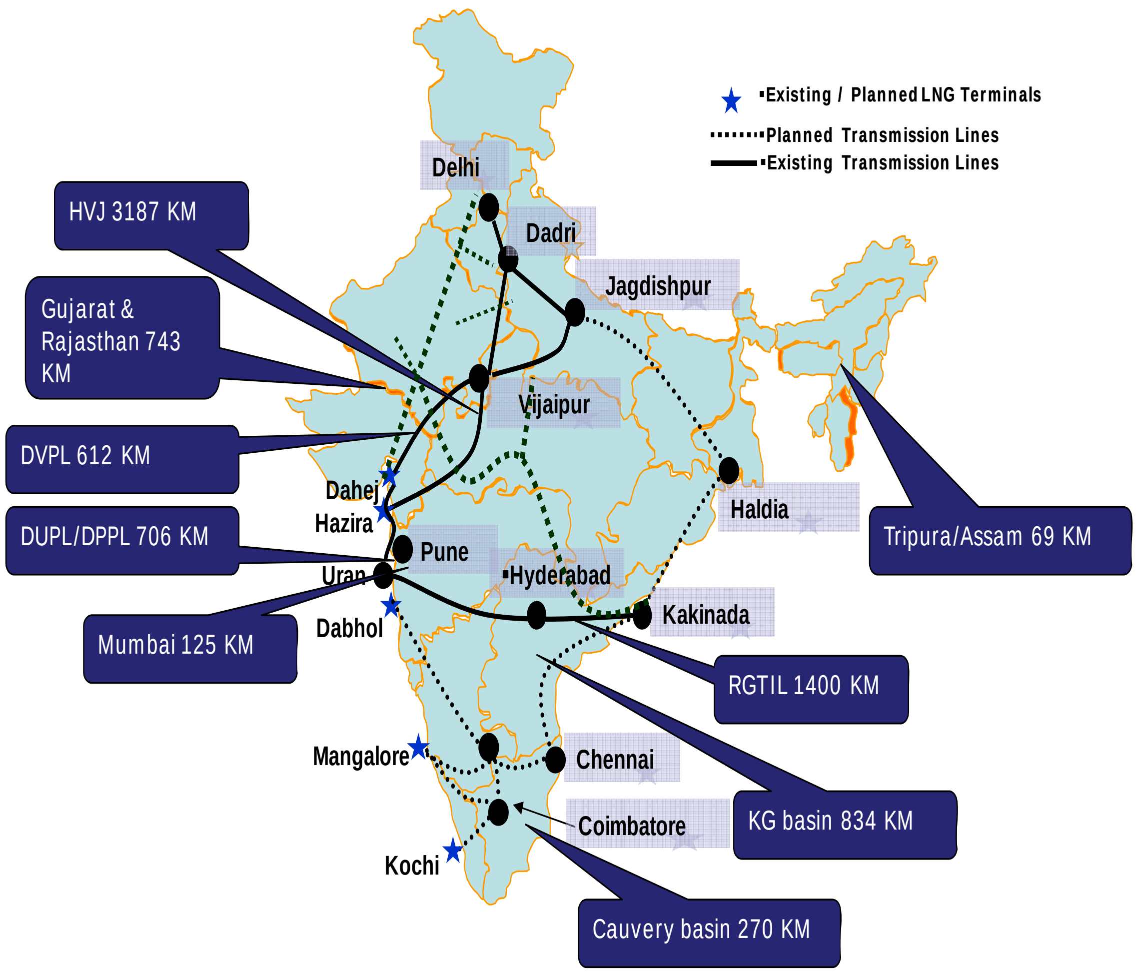
1152 km i.e. 11% of the network. The rest is owned by Assam Gas Company, OIL and Gujarat Gas.

The largest existing cross-country transmission system is the Hazira-Vijaipur-Jagdishpur trunk pipeline system, which traverses for a distance of 3,187 km. Reliance Gas Transmission Infrastructure Limited (RGTIL) plans to develop more pipelines with a total length of 2,875 km across India.

In Assam, the Assam Gas Company has a network of 560 km trunk pipelines and 1,150 km of distribution pipelines. Gujarat Gas Company Limited owns 116 km of transmission lines and 1,900 km of distribution lines. GSPCL has a pipeline network of 1,152 km along Hazira-Vadodara-Ahmedabad-Kalol-Himmatnagar-Mehsana-Rajkot-Morbi-Vapi that transports 20 MMSCMD of gas, including a large volume of LNG. This is being enhanced significantly through new transmission pipelines traversing the state. The network will be connected to the east-west pipeline of RIL through its 30 inch Bharuch-Jamnagar pipeline.

Several other pipeline systems have been proposed in the country, and currently feature in the authorisation process established consequent to the enactment of the legal framework under the PNGRB Act, 2005.

The following figure depicts the pipeline infrastructure in the country.



It is important to note that the pricing of the commodity has a strong bearing on the pipeline network development. To illustrate, a pipeline that is wholly or predominantly dependent on more LNG to be carried would inherently be constrained on account of the lesser number of buyers in a position to absorb the relatively higher prices and risks associated with LNG. In contrast, lowering of prices and price volatility would lead to immediate reduction in prices and price volatility for the end use consumers, would encourage consumption along the pipeline system, thus aiding its expansion.

IV CURRENT NATURAL GAS PRICING MECHANISM

The natural gas pricing scenario in India is complex and heterogeneous in nature. There are wide varieties of gas price in the country.

At present, there are broadly two pricing regimes for gas in the country - gas priced under APM and non-APM or free market gas. The price of APM gas is set by the Government. As regards non-APM/free market gas, this could also be broadly divided into two categories, namely, domestically produced gas from JV fields and imported LNG. The pricing of JV gas is governed in terms of the PSC provisions. It is expected that substantial gas production would commence from the gas fields awarded by the Government under the New Exploration Licensing Policy (NELP). As regards LNG, while the price of LNG imported under term contracts is governed by the SPA between the LNG seller and the buyer, the spot cargoes are purchased on mutually agreeable commercial terms.

1. APM GAS PRICING

APM gas refers to gas produced by entities awarded gas fields prior to the PSC regime. The prices of gas from these fields are administered by GoI. The Government raised the consumer price be revised from Rs.2,800/MSCM to Rs.3,200/MSCM with effective from July 1st 2005 for the following categories of consumers. It was also decided that all the APM gas will be supplied to only these categories.

- Power sector consumers
- Fertilizers sector consumers
- Consumers covered under court orders
- Consumers having allocations of less than 0.05 MMSCMD

This increase was on an ad hoc basis and it was decided that the Tariff Commission would examine the issue of producer price of natural gas. The Tariff Commission (TC) has since submitted its report and has recommended Producer price of Rs.3710/MSCM and Rs.4150/MSCM for ONGC and OIL respectively. TC has also recommended that the consumer price should be somewhat higher than the producer price, considering the substantial difference between the recommended producer price and the price of market gas/alternative fuels.

GoI also decided that the price of gas supplied to small consumers and transport sector (CNG) would be increased over the next 3 to 5 years to the level of the market price. With effect from May 6th 2005, the APM gas price to small consumers and CNG sector has been increased by 20%, to bring it to Rs.3840 / MSCM.

The price of natural gas for customers in the North-East has been kept at 60% of the price in the rest of the country. Accordingly, the price for power and fertilizers sector in the North-East is Rs.1920/MSCM and that for court-mandated and small scale consumers in the region is Rs.2304/MSCM.

2. PRICING OF GAS UNDER PRE-NELP PRODUCTION SHARING CONTRACTS

Production Sharing Contracts (PSCs) were executed by GOI with Ravva consortium and PMT consortium on October 28, 1994 and December 12, 1994 respectively. The price of natural gas is determined by the provisions of PSC signed by the consortium with GOI. Around 17.3 MMSCMD, 1 MMSCMD and 0.9 MMSCMD are supplied from PMT fields, Ravva fields and Ravva Satellite fields respectively under the pre-NELP PSCs. Out of this, GAIL supplies 5 MMSCMD from PMT fields and the production (1 MMSCMD) from Ravva fields at APM rate to APM consumers; the difference between PSC price and APM price is being made up through the gas pool account mechanism.

3. PRICING OF GAS WITH REFERENCE TO NELP PROVISIONS

As regards the gas from NELP fields, the Government constituted an Empowered Group of Ministers to consider inter alia issues relating to pricing of natural gas, produced under the NELP regime. It has been decided therein that the provisions of the NELP PSC should be honoured. The following price basis/formula for the purpose of valuation of natural gas has been approved by the Government in case of KG-D6 Block of RIL/Niko.

Selling price (in US $/MMBTU) = 2.5 + (CP-25)0.15 (in US$/MMBTU), where CP=crude price in US$/barrel, with cap of CP=US $60/barrel.

The price basis/formula comes to US$4.2/MMBTU for crude price greater or equal to US $60/barrel.

It was decided that price discovery process on arm's length basis will be adopted in the future NELP contracts, only after the approval of the price basis/formula by the Government. It was also decided that the price discovered through this process would be uniformly applicable to all the sectors.

4. IMPORTED GAS (LNG) PRICING

A contract was signed with RasGas, Qatar for supply of 5 MMTPA LNG (equivalent to about 18 MMSCMD) by Petronet LNG Limited (PLL) and supplies commenced from April 2004. This quantity has subsequently increased to 7.5 MMTPA wef. January 2010. The price for LNG has been linked to JCC crude oil under an agreed formula. However, the FOB price for the period up to December 2008 has been agreed at a constant price of $2.53/MMBTU. This price translates to RLNG price of $3.63/MMBTU ex-Dahej terminal. The price would vary on monthly basis from January 2009.

Further, in July 2007, PLL has signed another contract with RasGas, Qatar for supply of 1.25 MMTPA LNG from July 2007 to September 2009 to meet the requirement of Ratnagiri Power Project in Maharashtra.

In order to make the price of spot RLNG affordable, EGoM has decided in the meeting held on January 11th 2007 for pooling of prices of spot cargoes with LNG being imported on term contract basis. This Ministry accordingly issued orders on March 6th 2007 in compliance with the decision of EGoM. In addition to the above term contracts, LNG is also being sourced from spot market by PLL and Hazira LNG Pvt. Ltd. During 2007-08, an average quantity of about 5.7 mmscmd was brought into the country as spot cargoes.

The summary of all the prices are presented below:

Table 4.1 : Summary of prices prevailing in the country

Gas Source	Price ($/MMBTU)	Gas Source	Price ($/MMBTU)
PMT RRVUNL	4.60	APM North East at market price	1.79
PMT Torrent	4.75	APM Power	1.79
PMT others	5.65	APM Fertilizer	1.79
Rava	3.50	APM City Gas	2.15
Rava Satellite	4.30	CB/OS -2 Cairn GPEC	4.75
KG D6	4.20	CB/OS – 2 Cairn GTCL	4.60
APM North East-	1.08	Olpad (NSA) Niko	5.50

Gas Source	Price ($/MMBTU)	Gas Source	Price ($/MMBTU)
Power and Fertilizer			
APM North East- City Gas	1.29	North Balol (HOEC)	1.77
CB/OS -2 Cairn GSPC	5.50	*Dahej Term LNG	5.42
Hazira Niko- AGCL	4.61	Palej (HOEC)	3.50
Dholka	1.77		

Source: GAIL, MoPNG

*December 2009 Figure on GCV basis

The large variation in prices of a largely similar commodity supplied from various sources results in significant distortions in the end use markets. While a certain degree of differences in prices of supplies to consumers is inevitable, the wide variations have significant ramifications for customers. The impact is manifested in several ways. Producers of price controlled gas have little incentive to optimise production profile and costs. At the consumer end, wide divergence in prices make certain producers uncompetitive vis-à-vis others within the same industry. Artificially controlled and uneven price signals also distort price benchmarks for introducing new supplies, thus making sourcing and investment decisions more difficult and contentious. All of these have very significant impact for the economy, which is severely hampered on account of the constrained access to energy sources.

V NEED FOR PRICE POOLING

The Indian gas market needs to match customer expectations, gas infrastructure expansion with providing flexibility for new and marginal suppliers to enter the market. Price pooling is a mechanism where the potential for balancing the customer and developer expectation with that of suppliers.

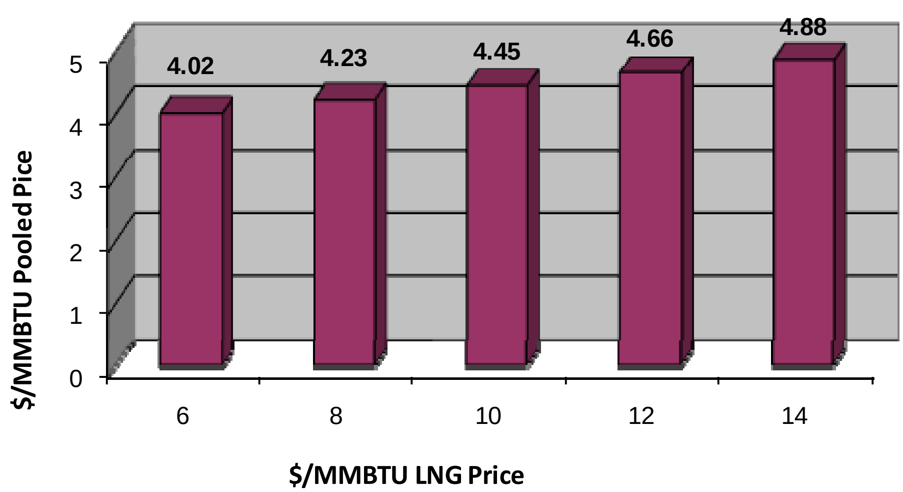
The need and benefits of pooling for the Indian gas markets need to be considered in the context of the market development objectives. These could be summarised as follows:

1. Introducing new gas sources in the market;
2. Ensuring stable price signals for long gestation investments based on gas;
3. Deepening the pipeline network to expand the gas markets geographically;
4. Sending appropriate price signals for efficient use of gas;

The Indian gas markets are relatively small as compared to the size of the economy, but are expanding rapidly. However, as commented earlier, the expansion has not kept pace with the demand. Domestic gas finds, while substantial, are inadequate to meet the burgeoning demand for gas. In particular, the demand from bulk consuming sectors like power and fertiliser is growing at a rapid pace. At the other end, the demand from city gas is also expected to increase rapidly in the coming years. As a result of this expansion of demand, the country is looking seriously at LNG as a potential source of supply expansion.

LNG, as an internationally traded commodity presents two challenges. Firstly, the price of LNG is generally linked to the price of crude oil, especially for long term supplies. The resultant prices of RLNG are typically significantly higher than the prices of domestic gas, including from the NELP fields. Secondly, the prices of such supplies being linked to crude are inherently volatile. The combination of relatively high prices and high volatility make it difficult for user industries like power and fertiliser to plan investments based on LNG.

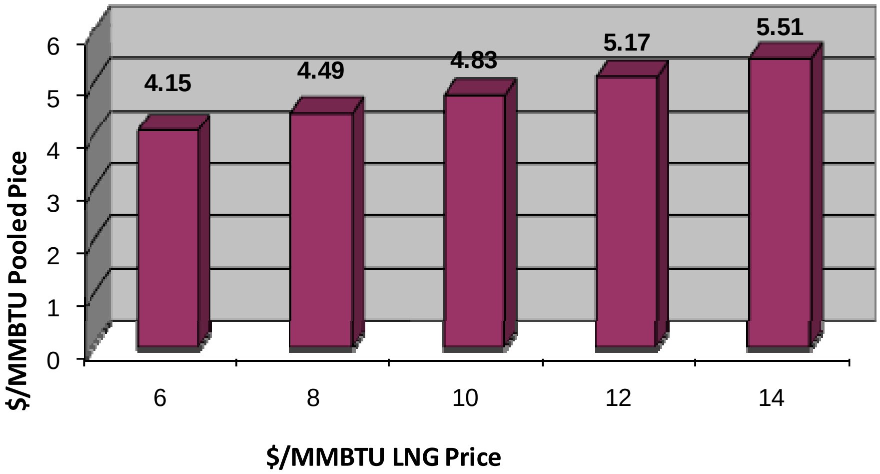
Price pooling can serve the objectives of introducing substantial quantities of new LNG supplies. The existing base of the pool would serve to reduce the price volatility, and given the impetus for infrastructure development. The graphic below illustrates the impact of 5 MMTPA of new LNG supplies (approximately adequate for 5000 MW of new power projects), on the existing cost pool in India, at various supply price points[1].



Pool Price at various LNG Prices for 5 MMTPA New Supply

[1] The existing supply base considered for this graphic is about 185 MMSCMD, considering a production of 90 MMSCMD from RIL KG D6 field.

The graphic below illustrates the impact of 10 MMTPA of new LNG supplies



Pool Price at various LNG Prices for 10 MMTPA New Supply

As apparent from the graphics, within certain limits, a substantial quantum of LNG can be introduced on account of reduction of volatility, which would be difficult were these supplies to be contracted individually by price sensitive user industries like power and fertiliser.

Commodity price pooling arrangements would also help implement a deeper pipeline network across the country. As with assets of user industries, a gas pipeline would be severely constrained were it to carry only or predominantly LNG for customers on account of the lack of such customers. In contrast, pooled commodity prices would permit such pipeline systems to attract a customer base, and ensure adequate flows along the pipelines, as well as providing the assurance of long term contracted gas flows to pipeline developers.

Finally, from an economic standpoint it is important to avoid a wide range of prices for the same commodity as this leads to inefficient consumption and seriously impairs inter–se competitiveness of the players in the same consuming industry. The one to one attribution of sources various buyers (as opposed to supply at a common price based on standard contracts) results in contractual inflexibilities both for buyers and suppliers, further raising risks and iniquities. It can well be construed that the prevalence of a large number of diverse pricing and contractual arrangements is seriously affecting market development and overall consumer interest. Price pooling options assume significance in this context.

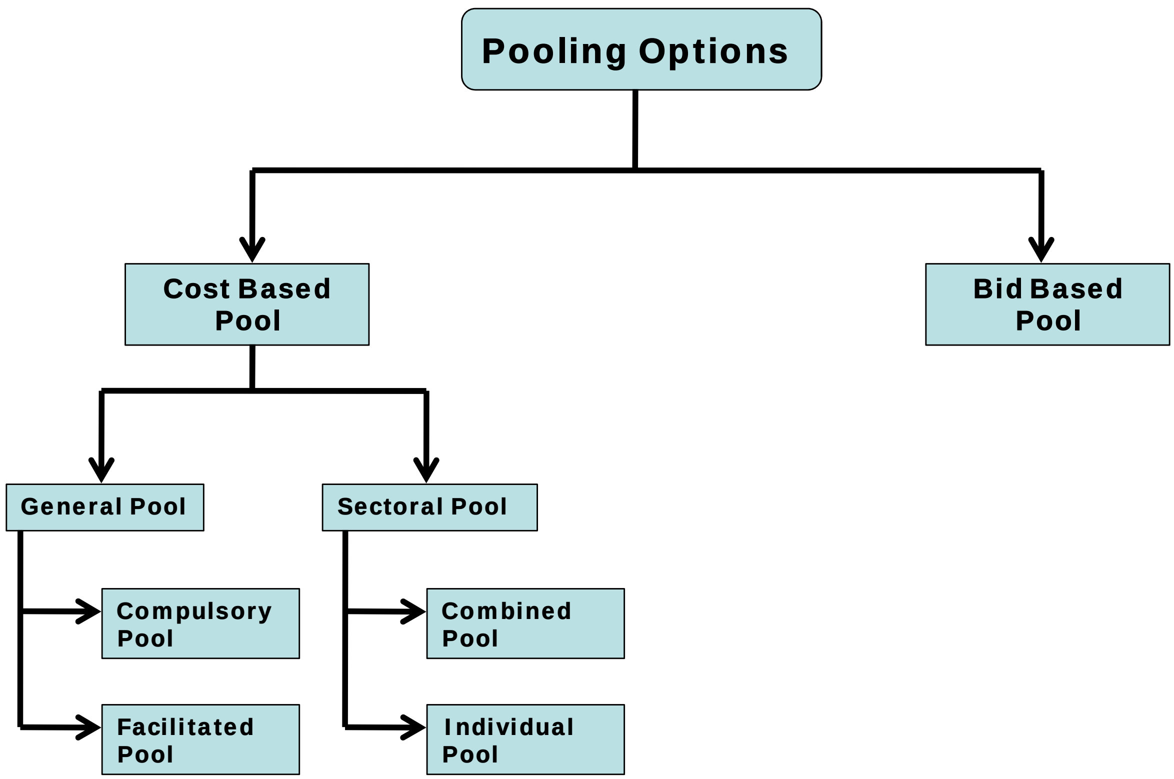
Price pooling arrangements can help address several of these issues. However such pools need to be designed considering the specific objectives of the market, the stage of market development, economic policies, legal frameworks, and the costs of implementation. The options in this regard are discussed in the following section, along with their relative advantages and disadvantages.

VI INTRODUCTION TO POOL PRICE MECHANISMS

This section of the report discusses the various options that can be considered for pooling of gas. A pool is an arrangement where outputs from different sources are pooled together scheduled according to increased costs, the technical and contractual characteristics and dispatched according to defined set rules of distribution. Price pooling mechanisms take into account either the costs of the various sources of gas and arrive at a weighted average pool price, or such prices based on demand and supply, typically through bid processes.

1. DEFINING THE TYPES OF COMMODITY POOLS

The various pooling options considered are schematically presented below.



The pooling options have been broadly divided into two major categories viz. Cost Based pool and Bid Based pool. Cost based pool has been further divided into General pool and Sectoral pool. The following section defines the various pools considered for the this study

- **General Pool** - In this type of pooling arrangement all the gas producers or traders participate in the pool. Gas is supplied to all the customers through the pool administrators. This could feature two basic options as variants.
    - Mandatory or compulsory pool - In mandatory pool all the gas producers or traders have to participate in the pool and subsequently all the sale of gas will happen through the pool. Similarly, all demand would be required to contract through the pool for supplies.
    - Facilitated pool - Facilitated pool does not make it compulsory for the gas producers or gas suppliers to participate in the pool. The gas producers or traders can participate in the pool and exit from the pool as per the defined rules of the pool. The same would apply for buyers from the pool.

- **Sectoral Pool** - Sectoral pool is specifically for pre-identified sectors. As regards this study, this has been considered for Power and Fertilizer segments, although variants could extend to other sectors as well. Two basic forms of sectoral pools have been considered.
  - Combined pool - In combined pooling arrangement there is a single pool for Power and Fertilizer. The gas at pooled price is supplied to customers from both the sectors through an identified mechanism.
  - Individual pool - In this type of pooling arrangement there will two different pools for Power and Fertilizer separately. The pool operator may or may not be same. The gas at pooled price is supplied to the respective customers through on identified mechanism. The pooled price may or may not be same for both the pools.

The above options have been discussed in the subsequent sections. It needs to be noted that in all options presented herein, the existing cost structures of the gas supply from producers (or importers) remain unchanged, and the revenues to be generated would correspond to these costs, plus the transportation costs, taxes and duties as at present. Hence there is no impact on subsidies as a whole, although the cost of gas to individual consumer costs would be rationalised as a result of the pooling arrangements. In subsequent years, with expansion of supplies in the pool, this would be altered based on the cost and quantum of additional gas supplies. Hence, irrespective of the option selected, specific pool rules would need to be agreed on the cost and quantity limits and implemented by the pool operator accordingly.

2. DETAILED DESCRIPTION OF THE OPTION CONSIDERED FOR COMMODITY PRICE POOLING

2.1. *COST BASED GENERAL POOL*

The following four options have been identified in cost based general pools.

- Option 1: Comprehensive compulsory - It would be mandatory for all the gas suppliers and gas traders to take part in this pool.
- Option 2: Comprehensive compulsory without spot RLNG - It would mandatory for all the gas suppliers to take part in this pooling arrangement, except for the spot LNG transactions, which would be kept out of the ambit of the pooling arrangements.
- Option 3: Facilitated pool without private spot and PSC gas - A voluntary arrangement with all the PSU gas producers, PSU spot LNG traders and long term LNG producers bringing their gas into the pool.
- Option 4: Voluntary pool without private spot - It is a voluntary pool opens for all the gas producers and gas traders except the private LNG players.

<u>Option 1: Comprehensive compulsory cost based pool</u>

As mentioned above, this is a cost based pool with all the gas producers and traders becoming a part of the pool. APM gas, Gas from NELP blocks, Long term LNG and Spot LNG will become part of this pool.

Rules of the pool

1. It would be compulsory for all the gas producers and traders to become a part of this pool.
2. The pool operator will forecast the pool demand and will be responsible for the demand supply balance of natural gas in the pool.
3. The pool operator (or its nominees) would be counter party to all the gas purchased in the pool from the Spot LNG market.
4. Pool operator will allocate the gas based on the individual demand from the gas customers.

5. This will be a tenured mechanism with the sunset clause identified ab-initio to facilitate the transition to a developed Natural Gas market.

Gas Source

Based on the existing identified sources, the table below provides the details of the gas from various sources that will be a part of this pool

Table 5.1: Cost based general pool option 1- Gas Sources and Prices

Source	Volume (MMSCMD)	Wt. average price ($/MMBTU)
ONGC/OIL	54.32	1.82
RIL-KGD6	57.14	4.20
PMT/ Rava /Rava St.	18.67	5.35
Long term RLNG	21.69	5.42
*Shell Spot	5.54	10.00
*Petronet Spot	1.59	10.00
Other Gas	2.70	4.73

*Spot Price is assumed at $10/MMBTU

Source: MoPNG and GAIL

The weighted average price for option 1 comes out to be $ 3.96/MMBTU. However it needs to be noted that the pool prices would vary with the variations in price of the constituent gas supplies. For example, the long term R-LNG price from Rasgas supplies is considered at $ 5.42/MMBTU Ex terminal (December 2009) and the corresponding weighted average cost of pooled gas is $ 3.96/MMBTU. However, considering continuation of the current crude prices at $ 80/Barrrel from February 2010, the long term LNG costs would increase to about $9.01/MMBTU Ex terminal in January 2012 and the corresponding weighted average cost of pooled gas will be $ 4.44/MMBTU.

Advantages and Disadvantages

A detailed analysis was carried out based on parameters such as volume, volatility, administration issues etc. for all the options. The following table provides the advantages and disadvantages of the Compulsory Comprehensive Pool arrangements.

Table 5.2: Advantages and disadvantages

Advantages	Disadvantages
• Thematic objectives of incremental gas supplies is achieved since the	• May lead to lack of transparency in spot LNG procurement

Advantages	Disadvantages
arrangements can potentially introduce new supplies	
• Large volumes dampen the effect of high Spot LNG prices. However if all spot is included then there could be significant volatility	• Pool administration and implementation expensive and contentious
• Increased LNG supplies in the country	• Negative signaling impact for future as price discovery of PSC gas is not possible
	• Legal issues- Will be prone to disputes. Also runs counter to PSC provisions
	• Runs counter to the direction of economic policies of the country
	• Allocation will be an issue in event of shortages- Gas Utilization Policy (GUP) to be detailed out

Option 2 : Comprehensive compulsory without spot RLNG

Option 2 is a cost based compulsory pool with all the gas producers except the spot RLNG traders becoming a part of the pool. APM gas, Gas from NELP blocks, Long term LNG will become part of this pool.

Rules of the pool - Rules of the pool will be same as in the case of Option 1, the only difference being that spot LNG would be excluded from the pool.

Gas Source

The table below provides the details of the gas from various sources that will be a part of this pool

Table 5.3: Cost based general pool option 2

Source	Volume (MMSCMD)	Wt. average price ($/MMBTU)
ONGC/OIL	54.32	1.82
RIL-KGD6	57.14	4.20
PMT/ Rava /Rava St.	18.67	5.35
Long term RLNG	21.69	5.42

Other Gas	2.70	4.73

Source: MoPNG and GAIL

The weighted average price for option 2 comes out to be $3.68/MMBTU

Advantages and Disadvantages

The following table provides the advantages and disadvantages of option 2.

Table 5.4: Advantages and disadvantages

Advantages	Disadvantages
• Lower volatility as compared to the Compulsory Comprehensive arrangements (Option 1)	• Militates against the objective of higher volumes of gas being sources through spots
• No pool administration issues relating to spot purchase of LNG	• Negative signaling impact for future as price discovery of PSC gas is not possible
	• Legal issues- Runs counter to PSC provisions of market discovery of prices
	• Runs counter to the direction of economic policies of the country
	• Allocation will be an issue in event of shortages- Gas Utilization Policy (GUP) to be detailed out through rules

Option 3: Facilitated without private spot RLNG and PSC gas

Option 3 is a cost based facilitated pool with all the PSU gas producers having an option to be a part of the pool. There is no compulsion for the gas producers to become a part of his pool. The gas producers can join and exit the pool as per predefined rules.

Rules of the pool

1. All the entities holding the customers will identify the demand and give it to the pool operator.
2. Pool operator will allocate the gas based on identified rules (Gas Utilization Policy).
3. Priority will be given to the power and fertilizer customers.
4. This will be a tenured mechanism with the sunset clause identified at the beginning to facilitate the transition to a developed Natural Gas market.

Gas Source

The table below provides the details of the gas from various sources that could be a part of this pool.

Table 5.5: Cost based general pool option 3- Gas Sources and Prices

Source	Volume (MMSCMD)	Wt. average price ($/MMBTU)
ONGC/OIL	54.32	1.82
Long term RLNG	21.69	5.42
*Petronet Spot	1.59	10.00

Source: MoPNG and GAIL

*Spot Price assumed at $10/MMBTU

The weighted average price for option 3 comes out to be $2.99/MMBTU

Advantages and Disadvantages

The following table provides the advantages and disadvantages of Option 3.

Table 5.6: Advantages and disadvantages

Advantages	Disadvantages
• Market discovery of gas price is possible	• Low volumes. About 50% of gas is out of the pool
• PSC gas price discovery possible	• Less liquidity in the market
• Voluntary hence less prone to disputes	• Allocation will be a problem
• PSU gas only- hence better control	

Option 4: Facilitated without private spot RLNG

Option 4 is a cost based facilitated pool with all the PSU gas producers and the NELP gas producers having an option to be a part of the pool. There is no compulsion for the gas producers to become a part of his pool. The gas producers can join and exit the pool as per predefined rules.

Rules of the pool

1. The gas produced from NELP can become a part of this pool after the Market Discovery of gas price.
2. The pool operator will forecast the pool demand and will be responsible for the demand supply balance of the pool
3. The pool operator will be a counter party to all the gas purchased in the pool from the Spot LNG market.
4. Pool operator will allocate the gas based on identified rules (Gas Utilization Policy).
5. This will be a tenured mechanism with the sunset clause identified at the beginning to facilitate the transition to a developed Natural Gas market.

Gas Source

The table below provides the details of the gas from various sources that could be a part of this pool

Table 5.7: Cost based general pool option 4- Gas Sources and Prices

Source	Volume (MMSCMD)	Wt. average price ($/MMBTU)
ONGC/OIL	54.32	1.82
RIL-KGD6	57.14	4.20
PMT/ Rava /Rava St.	18.67	5.35
Long term RLNG	21.69	5.42
*Petronet Spot	1.59	10.00
Other Gas	2.70	4.73

Source: MoPNG and GAIL

*Spot Price assumed at $10/MMBTU

The weighted average price for option 4 comes out to be $3.75/MMBTU (assuming all of the above sources are included).

Advantages and Disadvantages

The following table provides the advantages and disadvantages of option 4.

Table 5.8: Advantages and disadvantages

Advantages	Disadvantages
• Thematic objectives of incremental Gas supplies is achieved	• Pool administration and implementation expensive and contentious
• Large volumes dampen the effect of high spot LNG prices	• PSC gas holders may not agree- In which case the size could be smaller
• Keeping out private spot out reduces volatility	• Relatively higher governance issues in terms of spot purchases
• Governance issues are less as compared to compulsory pool with spot (Model 1)	• Pool operator will be a counterparty to spot transaction, hence requires significant institutional structures (although lesser that a compulsory

Advantages	Disadvantages
	pool)
• Price discovery for PSC gas is possible	• Government may appoint a pool operator among the PSU companies

Summary of the options studied

Based on the analysis of the above four options, it was observed that voluntary arrangements would be very difficult to implement on account of the challenges in developing a consensus on pooling without a mandate from the GoI to do so. Hence, while attractive from a conceptual standpoint, Option 3 and 4 would be very difficult to implement.

Among the two compulsory arrangements proposed, it would be difficult to implement any arrangement that includes spot purchases. The pool administration would become extremely cumbersome and contentious. Spot LNG purchases require quick decisions based on market needs. Since a single compulsory pool would be not flexible enough to identify short term market needs, the decisions of the pool administrator in this regard would be difficult to arrive at. Considering these factors, we believe that among the general pool options, Option 2 (Comprehensive Compulsory without Spot RLNG) appears to be the most practical.

The following table provides the summary of all the four options as a part of cost based general pool.

Table 5.9: Summary of cost based general pool

Pool Option	Description
Option 1 - Comprehensive Compulsory-With Spot LNG	• All gas in country – domestic and imported – is pooled by a pool operator • Pool operator aggregates demand and determines supply needs, including short term requirements. Nominee procures spot RLNG • Detailed Gas utilisation Policy (GUP) and consequent rules determine volume allocations • Pool operator schedules gas demand and supply, undertakes balancing and settles trades
Option 2- Comprehensive Compulsory-Without Spot RLNG	• Same as above, except spot RLNG excluded
Option 3- Facilitated Pool Arrangement- Without PSC Gas and Private Spot RLNG	• Voluntary arrangements , instead of compulsory • PSC gas and RLNG out of ambit to enable “market discovery” of prices • Essentially a PSU pool
Option 4- Facilitated Pool Arrangement- Without Private Spot RLNG	• Same as above, except for PSC gas included in pool based on mutual agreement

2.2. COST BASED SECTORAL POOL

A sectoral pool aims at serving the needs of specific consuming sectors only. The objective of such a pool would essentially to be to meet the expansion and price stabilisation needs of the selected sectors, leaving the other sectors free to access their supplies from other sources.

The merit of these arrangements lies in addressing the needs of the sector that are particularly sensitive to prices and price volatility. Among these sectors, power and fertiliser assume prominence, both featuring huge amounts of government subsidies and price control. Hence these sectors have been identified for specific analysis. In combination, these two sectors account for about 70% of the gas demand.

The following two options were considered under the cost based sectoral pool.

- Combined cost based sectoral pool: One single common pool for Power and Fertilizer sector.
- Individual cost based sectoral pool: Two separate pools for Power and Fertilizer sector.

The above mentioned options are discussed in detail in the subsequent section.

Option 1: Combined cost based sectoral pool

Under this option there will be a single pool for both the sectors viz. Power and Fertilizer. Natural Gas from various sources will become a part of these pools, but only to the extent of consumption by the customers in these two priority sectors.

Rules of the pool

1. The demand in the pool will be identified by designated Pool Operator for the short (<=1 year) and medium (2-3 years) term.
2. The gas allocations from the pool will be done in accordance to the Gas Utilisation Policy.
3. The incremental requirements will be contracted by Pool Operator/nominee from various available sources, including LNG.
4. This will be a tenured mechanism with the sunset clause identified at the beginning to facilitate the transition to a developed Natural Gas market.
5. In case of power sector the key decision would be on whether to
    - o Include only the demand from long term bid based or price regulated contracts or
    - o Include all power sector demand

Source-wise gas supply to the power and fertilizer segments

The table below provides the details of the gas from various sources supplied to the power and fertilizer sector.

Table 5.10: Option 1 - Cost based Sectoral Pool

	Source	PMT/ Rava/ Rava St.	KGD 6	APM	*Term LNG	Others
Combined Pool	Supply to Power (MMSCMD)	5.41	24.4	23.38	5.13	1.27
	Supply to Fertilizer (MMSCMD)	4.22	14.14	13.47	9.35	0.02
	Price ($/MMBTU)	5.35	4.20	1.79	5.42	4.73

Source: MoPNG and GAIL

The weighted average price for combined sectoral pool, considering the current supplies comes out to be $3.61/MMBTU

Advantages and Disadvantages

A detailed analysis was carried out on parameters such as volume, volatility, gas supply, administration issues etc. for all the options. The following table provides the advantages and disadvantages of option 1.

Table 5.11: Advantages and disadvantages

Advantages	Disadvantages
Moderate volatility	Allocation will be an issue in event of shortages. Allocation based on identified rules
Desired effect of pooling can be achieved as pooled price gas will be supplied to the key segments which requires gas price stability	Power and fertilizer sectors would have separate growth trajectories. A common pool may result in one category of consumers subsidizing the other
Price discovery of gas is possible however mechanism for price discovery of gas out of power and fertilizer sector will have to be identified	
Policy directive adequate for implementation	

Option 2: Individual cost based sectoral pool

There will be two separate pools for Power and Fertilizer. Natural Gas from various sources will become a part of these pools, but only to the extent of consumption by the customers in these two priority sectors respectively.

Rules of the pool

1. Rules will be similar to option 1 except that there will be two independent pool operators which will administer the respective pools

Source-wise gas supply to the power and fertilizer segments

The table below provides the details of the gas from various sources supplied to the power and fertilizer sector.

Table 5.12: Cost based sectoral pool option 2-

	Source	PMT/ Rava/ Rava St.	KGD 6	APM	*Term LNG	Others
Individual Pool	Supply to Power (MMSCMD)	5.41	24.4	23.38	5.13	1.27
	Price ($/MMBTU)	5.35	4.20	1.79	5.42	4.73
	Source	PMT/ Rava/ Rava St.	KGD 6	APM	*Term LNG	Others

Individual Pool	Source	PMT/ Rava/ Rava St.	KGD 6	APM	*Term LNG	Others
	Supply to Fertilizer (MMSCMD)	4.22	14.14	13.47	9.35	0.02
	Price ($/MMBTU)	5.35	4.20	1.79	5.42	4.73

Source: MoPNG and GAIL

The pool price for power sector pool comes out to be $3.48/MMBTU and for fertilizer sector pool comes out to be $3.81/MMBTU

Advantages and Disadvantages

A detailed analysis was carried out on parameters such as volume, volatility, administration issues etc. for all the options. The following table provides the advantages and disadvantages of option 2.

Table 5.13: Advantages and Disadvantages

Advantages	Disadvantages
Two different pools for the two priority sector will lead to two different pool prices based on the individual affordability of the sectors, but will prevent inter-se cross-subsidization	Allocation will be an issue in event of shortages. Allocation based on identified rules
Desired effect of pooling can be achieved as pooled price gas will be supplied to the key segments which requires gas price stability	Smaller pool size could lead to relatively higher volatility
Price discovery of gas is possible however mechanism for price discovery of gas out of power and fertilizer sector will have to identified	
Policy directive adequate for implementation	

Summary of the options studied

The following table provides the summary of two options studied as a part of cost based sectoral pool.

Table 5.14: Summary of cost based sectoral pool

Pool Option	Description
Option 1 – Individual Pool	• Specific and separate pool for power and fertiliser industries • Demand to be identified by designated Pool Operator for the short and medium term • Domestic gas allocations to be made as per Gas Utilisation Policy • Incremental requirements to be contracted by Pool Operator/nominee from various available sources, including LNG • For power key decision would be on whether to: – Only the demand from long term bid based or price regulated contracts OR – Include all power sector demand
Option 2- Combined Pool	• Same as above, except that Power and Fertiliser operate in a combined pool

On the balance we believe that even though it would be slightly more volatile, separate sectoral pools (Option 1) would be more practical among the two options.

A key issue in this context is the adequacy of policy directives of Government of India to migrate to a pool pricing regime as compared to customer prices based on individual supply contracts. For this the various types of supply need to be considered, viz.,

- APM Gas
- PSC Gas (e.g. KG D6)
- R - LNG

The study of the APM contract provided to us indicates that the following clause provides a clear understanding that the seller shall have the right to fix the gas price as per the Government of India directive.

" The SELLER shall have the right to fix the gas price at any time in future as per directive , instruction, order etc of the government of India issued from time to time and the BUYER shall pay to the SELLER such price of gas fixed by the SELLER".

<u>Since the provisions unambiguously establish the right of Government of India to set the prices, we do not anticipate any legal challenges in case of APM Gas.</u>

<u>In the case of PSC gas,</u> it is the position of Government of India that the allocations have to be in accordance with the Gas Utilisation Policy, which is the prerogative of the Government. Further, the prices have been set through an Empowered Group of Ministers (E-GOM) process, and the consequent decisions of constitute matters of policy. Since all sales are consequent and subject to policy (with the Government being the owner), price pooling based on policy directives would be essentially a continuation of the current gas pricing approach adopted by Government of India.

In case of R-LNG, since the supplies are essentially facilitated by the proposed pool pricing regime, opposition from existing or future customers of R-LNG to the pool pricing framework is not foreseen.

Considering the above, in our opinion inclusion of subject natural gas in the Union List in Schedule VII of Constitution of India empowers the Government of India to issue policy directions regarding price pooling, and that such pooling mechanism that addresses long term energy security interests would be possible through policy directives, particularly since the core contractual rights of the sellers and buyers are not infringed upon.

Two additional factors need to be considered. Firstly, the review of existing APM and PSC contracts with customers reveals that the prices are essentially passed through by the purchasers through the tariff process. Hence there is no direct impact on the procuring entities, who are also relatively few in numbers (and hence easier to consult and take on board). More importantly, the entire purpose of the proposed pooling exercise is to facilitate additional supplies and hence growth of these customers. The additional supplies would enable major customers like NTPC, Pragati Power, etc to expand their gas based portfolio and would also help meet the country's quest for energy security and clean energy generation. Hence it is anticipated that the respective nodal ministries would support the development of sectoral pools, and that the policy would receive active co-operation and support of these ministries.

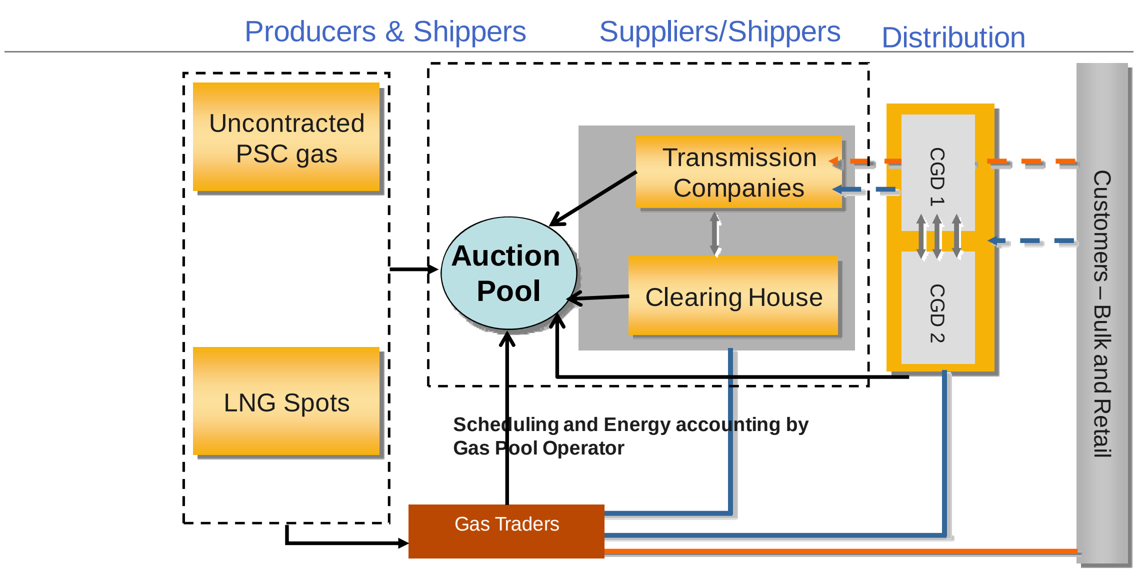
2.3. BID BASED POOL

Unlike the options in the cost based pools which has to be implemented on a standalone basis, it is proposed that the bid based pool will co-exist with the long term contracts or any of the identified cost based pooling mechanisms.

Key features of bid based pool

1. Generally the volumes in case of bid based pool is not high (generally in the range of ~10-15% of the total volume of gas)
2. Spot LNG, Government of India share of profit gas and leftover PSC gas which is not contracted (if any) can become part of this pool.
3. Commodity and financial transaction will be monitored and controlled by an independent pool operator or platform like in the case of power sector.
4. It is consistent with economic policy of the country to move towards market determined prices for natural gas in the country

The following figure shows the institutional structure and the mechanism of bid based pooling.



Rules of the pool

1. The gas producers and traders will indicate the volume to be pooled into the pool on a daily basis.
2. Customers will indicate the requirement of gas on daily basis.
3. The pool/auction platform will discover the price of gas on daily basis.
4. The clearing house will settle all the financial transaction between the gas producers, gas traders, transmission pipeline company and the gas customers.

Advantages and Disadvantages

The following table highlights the advantages and disadvantages of the bid based pool.

Table 5.15: Advantages and Disadvantages

Advantages	Disadvantages
• Automatic indication of market prices. Market discovery of PSC gas is possible	• High market concentration. Capability of large players to dominate and alter prices
• Ability to bring in more LNG in with market prices same as reference. India can emerge as a gas hub	• Infrastructure dependent – Till more pipelines come in, operating the pool will be difficult due to network constraints
• Lesser governance issues as compared to cost pooling options (especially for LNG Spots)	
• Consistent with economic policy	

Considering the nascent and developing nature of the gas transportation infrastructure we believe that a bid based pool could take another 3-4 years to implement. It needs to be noted that the bid based pool could only be a small part of the market and the bid based pools will co-exist with long term contracts or cost based pools. We recommend a more detailed study for the introduction of bid based pools at an appropriate juncture.

2.4. COMPARISON OF THE PREFERRED POOLING OPTIONS

As mentioned, among the options considered, two basic variants were considered feasible for further evaluation:

- Option 2 of General pool - Comprehensive Compulsory without Spots
- Option 1 of Sectoral Pools – Individual pools for the Power and Fertiliser sectors.

Between the two options, it is essential to select one single preferred framework for the proposed pooling arrangements. A set of criteria have been developed for this purpose, and are provided below:

- Ability of the mechanism to introduce new volumes
- Potential to contain price volatility
- Conformance to legal framework of PSC's and the economic framework of the country
- Minimizing the pool administration issues
- Continuing the price discovery mechanism under existing production sharing contract
- Minimisation of regulatory issues
- Signalling impact for new investment in E&P as well as in downstream sectors.

The following table summarizes the comparison of the two preferred pools on the above mentioned criteria.

Table 5.16: Comparison of preferred options

Aspect	General Cost Pool (Comprehensive Compulsory w/o Spot LNG)	Industry Pool (Individual)
Overall volumes	High (almost entire market)	70 – 80% of the future market
Introducing new volumes	Yes, but limited to long term LNG.	Long term and spot LNG possible
Containing volatility	High	Moderate to High
Conformance to legal and economic framework	Significant issues. May need new legislation	Policy direction adequate
Minimizing Pool Administration issues	Not met	Met
Continuance of price discovery mechanisms under existing PSCs	Not tenable	Tenable. Existing price discovery mechanism continues
Regulatory issues	None (relates to commodity)	None (relates to commodity)
Signalling impact for new E&P and competitive markets	Negative	Not negative

Based on the above analysis, it is apparent that a sectoral pool would be more practical at this juncture.

2.5. KEY ISSUE- SHOULD MERCHANT POWER BE EXCLUDED FROM THE POOL?

Merchant power refers to power projects that sell into the competitive power markets. In an integrated energy chain based on competitive markets, these projects take market risks on both sides. However in a cost based pool there is an apparent difference between arrangements on the cost side (cost pooled) and on the revenues (market based), were such projects to be included in the cost pooling arrangements. Inclusion (or exclusion) has both merits and de-merits, as articulated below:

Aspects in favour of exclusion:

- The Pool prices will include cheaper APM gas and the merchant generators will benefit from the same while profiting from competitive power market prices. There is a large spread between price of gas and market prices of power.
- Pooling is essentially a de-risking mechanism. Merchant power should accept market risks on both demand and supply.

Aspects against exclusion:

- Exclusion of the merchant power would lead to administrative issues. Mix of long term contract versus spot sales in power charge from time to time and hence the pool regulations will become cumbersome and will be prone to disputes.

- Lower risks in gas markets should translate to more supply and greater competition in the power markets which may result in prices falling, however power prices in competitive markets are set to fall even otherwise.

From a practical standpoint, the prices of power in the short term market have reached very high level but have been falling since then. The following table highlights the prices of short term transaction of electricity

Table 5.17: Price of short term transaction of electricity (Rs./KWh)

Sr. No	Type of Transaction	Price of short-term transactions of electricity					
		Mar 09	Apr 09	May 09	July 09	Sep 09	Oct 09
1	Bilateral through traders	7.43	7.21	6.82	4.75	4.73	5.07
	RTC	7.35	6.83	6.60	4.72	4.60	4.86
	PEAK	8.08	9.05	8.18	5.92	6.02	6.48
	OFF PEAK	7.53	8.47	8.03	4.98	5.48	5.80
2	Power Exchange						
	PX (IEX)	8.33	10.10	6.84	4.81	4.00	4.73
	PX (PXIL)	8.54	10.18	8.74	4.85	4.32	5.18
3	UI						
	UI (NEW Grid)	4.85	5.36	4.17	4.12	5.02	5.83
	UI (SR Grid)	8.20	6.04	3.99	4.67	4.20	4.24

Source: CERC Market monitoring cell

It is also important to note that the prices in the electricity markets are expected to soften over a period of time. Forward curves developed by Mercados for the electricity markets are indicative of this trend. The following table depicts the project monthly price formation in the Electricity Spot markets

Table 5.18: Project monthly price formation in electricity spot market (Rs./KWh)

	2010-11	2011-12	2012-13	2013-14	2014-15
Apr	6.38	6.09	5.36	4.66	5.21
May	5.98	5.49	3.88	4.24	4.51
Jun	5.70	5.09	4.00	3.56	3.88
Jul	5.60	5.01	3.39	4.67	5.37
Aug	5.59	5.01	3.19	4.54	4.99
Sep	5.58	5.01	3.07	4.31	4.79

	2010-11	2011-12	2012-13	2013-14	2014-15
Oct	5.97	4.37	3.25	3.30	3.41
Nov	6.02	2.78	3.14	3.22	3.36
Dec	6.23	3.14	3.47	3.55	3.78
Jan	6.25	3.14	3.28	3.39	3.85
Feb	6.34	3.35	4.01	4.10	4.27
Mar	6.43	3.54	3.78	3.86	3.99
Average	6.01	4.34	3.65	3.95	4.28

Source: Mercados Analysis

As apparent, the prices would be substantially lesser on the average over time. Hence, based on the anticipated price trends and considering the ease of implementation of the proposed mechanisms, we recommend that all gas based power be permitted to be a part of the pool

2.6. SETTING UP OF POOL -KEY ELEMENTS

Setting up the pool will require a series of measures to be taken to establish and operationalise the pool. The key elements essential for setting up of a gas pool mechanism are stated below:

1. Pooling policy need to be issued by Government of India
2. A Pool Administrator need to be notified
3. The Pool Administrator will develop detailed pool rules relating to:
    a. Forecasting of demand
    b. Identification and notification of new supplies from various sources
    c. Identification of balance requirements for importation
    d. Allocation of importation requirements to various importers (preferably PSU)
    e. Treatment of shortages- Prioritisation among designated customers
    f. Detailed pool procurement rules
    g. Guidelines for designated customers with respect to drawing from pool
    h. Supply accounting rules
    i. Billing procedures for suppliers to designated customers as per pool guidelines
    j. Collection and payment security related procedures
    k. Information management, dissemination and disclosure
    l. Dispute resolution mechanism
    m. Pool administrator conduct and compensation rules
4. Mechanisms for introduction and amendment of various rules and guidelines would need to be set up
5. Pool Governance arrangements would need to be established. These would include:
    a. Operating committees for various operating aspects (forecasting, billing, settlement etc.)

   b. Operations review committee (periodic review of efficacy of arrangement and rules. Recommendations on changes);

   c. Audit committees

6. Amendments or modifications to existing contracts novated to the pool would need to be made.

   a. Notification of DCs and modification of the contracts

   b. Modification of supply contracts to the extent required by the pooling arrangements

   c. Modification to transportation contracts

7. Review arrangements after a defined time period would need to be set out.

An important aspect to consider is the taxation regime for gas. At present there are a wide range of taxation regimes that apply to gas from various sources, both at origin and at point of sale. Pooling of prices would result in the costs of feed gas varying from the sale price under the supply contract. While in case of PMT gas supplied under the APM mechanism a similar situation has been addressed (through the Gas Pool Account), and the same can be done for the sectoral pool, we would recommend a relook at the taxation regime and suggest simplification of the same. In particular since it is the stated objective of Government of India to reach gas out as a clean source of energy across the country, according gas the status of Declared Goods would merit consideration.

2.7. POOL OPERATION MECHANISM

The day to day operations of the pool will need to be based on detailed procedures. The Pool Operator would be central to the proposed arrangements and would play a major role in finalizing the terms and conditions for new gas entering the pool, as well as the management of the entire pool operations. The overall scheme proposed for this are indicated below:

1. Pool operator will forecast Short Term (Up to 1 year) and Medium Term Demand (3-4 years) every month for Designated Consumers.

2. The demand will be confirmed by the Designated Consumers.

3. The pool operator will decide on the probable mix between domestic gas (based on availability), Term LNG and Spots.

4. The pool operator will allocate the demand to empanelled/identified suppliers (sellers, shippers and importers) as per agreed allocation mechanisms.

5. The gas suppliers will contract at appropriate time with the Designated Consumers in line with the pool rules and allocations. The Pool operator will be informed about the contracts concluded and the agreements would be lodged with the Pool Operator.

6. The pool operator will conduct periodic review for various kinds of procurement to modify procurement schedules.

7. Metering will be done at the various supply and off-take points by the gas transporters based on identified contractual volumes (for the Designated Consumers) and actual.

8. The metered data will be submitted to the pool operator.

9. The pool operator will thereafter prepare the pool accounts, computing the average pool prices and quantities for the month.

10. The sellers will issue bills to the Designated Customers at the pool prices for the quantities supplied.

11. Buyers will be required to pay into a designated Clearing House set up for the pool at the pool prices, which shall include the following

    a. Pooled Commodity Prices

    b. Marketing margins of sellers

    c. Pool administration charges

12. The Clearing House will collect the amounts and thereafter distribute it to the various entities as per agreed commodity costs and marketing margins

13. Designated Customers will maintain adequate security with the Clearing House. This security will be drawn down in event of payment default

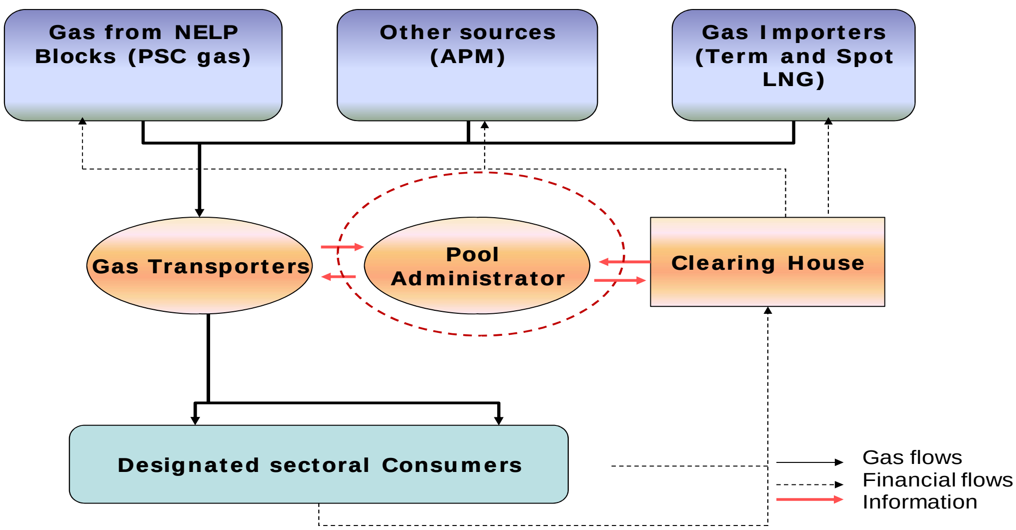
14. The pool operator will be compensated adequately for the costs and the pool design will ensure that there are no residual risks on the pool operator. By design the pool will be revenue neutral.

2.8. INSTITUTIONAL MECHANISM

The institutional arrangements in the pool would be the key to successful implementation, and the pool administrator would have a central role in this process. The pool administrator would forecast demand and supply, schedule and dispatch gas, meter, bill and notify the gas pool accounts and be responsible for smooth functioning of the pool.

We also propose that a clearing house be instituted for the pooling arrangements. The clearing house could be on the lines of those operating in the securities markets. They would be a repository for the contracts, maintain pool accounts, trading margins and security, settle trades and make payouts, and ensure smooth financial and commercial functioning.

The following figure illustrates the institutional mechanism required for a pooling arrangement to be followed separately for the two sectoral pools (power and fertiliser).



The dotted arrows in the figure represent the financial flows from the customers to the clearing house and subsequently from clearing house to the gas producers and traders. The plain arrows represent the gas flows from gas producers and gas traders to transmission lines and subsequently to the respective customers.

The pool administration would feature participation of the user ministries (Power and Fertiliser) for sourcing and allocation of supplies and governance of the respective pools. The pool would also need to set out certain clear limits for quantities set out for procurement and corresponding costs.

VII INTERNATIONAL GAS MARKETS: PRICING SYSTEMS

1. INTRODUCTION: OIL INDEXATION VERSUS HUB PRICING

In North America and the United Kingdom there was a certain similarity between the development of oil and of gas as a commodity, based on natural endowments of and distribution of resources and on successful sector reform. A liquid gas market has developed in both North America and the UK during the past 20 years.

The gas hubs in North America were created by industry at appropriate places, with Henry Hub[2] in Louisiana being the most prominent and important of these. By contrast, the National Balancing Point (NBP), a notional point at which gas is traded in the UK, was created by regulation. Both the UK and the North American markets have many players and show substantial demand elasticity based on gas demand for power generation.

There are specific features of the UK and North American gas markets which have favoured the development of gas as a commodity in these markets. Firstly, and most importantly, the development of the gas industry in these countries was based on domestic resources. North America was self sufficient until the end of the 20th century. The UK was not only self-sufficient, but was even briefly a gas exporter at the end of the century.

It should also be noted that the geology of North America (except for fields adjacent to the Beaufort Sea) as well as on the UK Continental Shelf is characterised by a large number of small to medium sized gas fields and an absence of giant structures.

In North America and in the UK, gas-to-gas competition is well developed and gas prices are no longer contractually pegged to oil prices but follow a development of their own. However, a de facto long-term average correlation between oil and gas prices remains due to substitution effects over longer periods.

Box 1 – Concept of gas (trading) hub

A gas hub is a "point" (physical or virtual HUB) where gas trading is facilitated by an operator (Hub Operator). Basically, the Hub Operator organizes the exchanges: receives & treats the trading notifications (nominations) of the parties: dispatching, matching, confirmation, monitoring, reporting services.

If the Hub Operator offers a number of services that facilitate trading, the hub is usually called "gas trading hub".

The main features of physical and virtual hub may be comparatively summarised as follows:

"Physical Hub"

• Gas is exchanged at precise physical location (e.g. a flange or a place where several pipelines connects to each other)

• Eligible gas for trading: gas passing at this location

• Physical players: Gas is delivered/off-taken to/from this location by physical players

• Pure traders: pure traders buy & sell at this location, they never move the gas to/from the

[2] The indicator for liquidity is usually called 'churn'. Churn is the ratio between traded volumes and delivered volumes. A churn of at least 15 is usually considered to be the threshold for a liquid market. Henry Hub has a churn of about 100, indicating high market liquidity. For comparison: on the oil side the churn of WTI and Brent is about 500. The churn on the NBP rose to about 15 until 2004 and then dropped for some time to 10, placing the NBP at the edge of being considered as a liquid market. European players, who prefer a strategy of vertical integration, have now replaced US firms in the UK power market, leading to lower volumes on the traded market.

Hub

"Notional Hub"

Gas is Exchange in a zone, a part of a gas network (e.g. national or regional gas network

• Eligible gas for trading = Entry paid gas = gas that entered the zone

• Physical players: gas is imported/exported/sold to end consumers (which are within the zone) to/from this zone by physical players

• Pure traders: pure traders never import/export gas to/from the zone.

Typically, the Hub operator does not actively put the parties into contact. Usually, trades are concluded bilaterally between parties (Over-the-Counter). Such deals can be carried out directly between the parties, involved, but many deals are put together by brokers. Traditional voice brokers work over the phone, but many brokerages now run computer trading platforms that display prices over the internet.

In some case, screen trading is also offered on the Hub; in this case, the hub is called Gas Exchange. Parties put anonymous bid/offer on a screen and the transaction are automatically concluded through the screen, the Hub Operator of being the "central counter party"; this allows full anonymity.

Key features of a gas trading hub

A successful gas trading hub has two basic characteristics: first and foremost it must be possible to easily move gas into and out of the market, whether the market is defined as a single point or as a whole area (virtual hub); second, there must be a use for the gas, either through the existence of a significant customer base, or through the demand from other markets that can be reached from the traded hub.

An important requisite for a trading hub is the ability for market players to manage volume risk (swings in consumer or export demand, compared to production or import supply) at a competitive cost. For a gas marketer, volume risk can be mitigated either by the use of storage or by having a customer base of a size and mix that matches the supply characteristics; similarly, a gas consumer will manage his volume risk by purchasing flexibility services from his supplier, or by having access to storage himself. Most hubs in North America also have access to significant quantities of storage.

Another major element of trading hubs is the legal and financial framework of the marketplace. For existing markets a number of master trading agreements have developed, most noticeably the EFET (European Federation of Energy Traders) contract for physical gas trading, and various annexes to the ISDA (International Swaps and Derivatives Association) contract. These frameworks contain the basic legal text for most standard provisions, serving as a foundation on which contracts are negotiated.

We can thus summarise the minimum requirements for a successful new trading market as:

- *Access to gas sources, and to customer base*
- *Possibility of managing volume risk for all market participants at a competitive cost*
- *Low barriers to entry for new players, known contractual setup and possible clearing services, with low transaction costs*
- *Managing price risk, through the market (existence of a forward/futures market)*
- *Fairness and transparency, leading to confidence and liquidity.*

In contrast to the situation in North America and the UK, gas markets in the rest of the European Union (excluding the Netherlands), and in Japan and Korea have developed based on imported gas. These markets have been shaped by the wish of exporting countries to maximise the rent from gas exports as a compensation for the depletion of their finite resources. The EU depends for 50% of its consumption on three large gas-exporting countries: Algeria, Norway and Russia.

The structure and concentration of gas supply to Continental Europe and to Japan and Korea, and their dependence on imports, makes these cases very different from North America and the UK. In turn, this suggests that differences in market structure are not only a question of sector reform.

In China, like other energy prices, natural gas prices have been under government control. To promote the use of natural gas use, the government has maintained a "cost-plus" based price regime, keeping the prices at a relatively cheap level compared to international markets. This gas was to a large extent possible due to China's self-sufficiency in natural gas. However, given the projected significant increase in LNG imports (which started in 2006), the price regime is now being challenged.

2. NORTH AMERICA

The North American (USA and Canada) natural gas transmission system is sufficiently interconnected that it operates virtually as a single system.

Liberalisation in the North American gas market started in 1979. A highly competitive market has evolved along the whole value chain.

The US liberalisation, coming at a time of sharply rising energy prices as a result of the first oil shock, created an extended period of surplus in the US – the 'gas bubble', which lasted until the mid 1990s. Continued growth in US demand beyond that point was increasingly supported by imports from Canada.

The North American market system features open trading in gas as a commodity and in pipeline capacity to move the gas to market. The centrepiece of the pricing system is Henry Hub, a pipeline junction in South Louisiana. This is the basis both of spot market trading and in futures trading on the New York Mercantile Exchange (NYMEX). The trade press reports on prices at other hubs and their differences from Henry Hub are referred to as 'basis differentials'.

2.1. BRIEF DESCRIPTION OF THE NORTH AMERICAN GAS MARKET

The North American market consumes annually 770 bcm compared to 540 bcm per year in IEA Europe. As a whole, North America is almost self-sufficient, but there is considerable trade between its component parts – overall, the US imports around 14% of total consumption from Canada.

The pipeline infrastructure linking Canada and the US operates virtually as an interconnected system. The interstate pipeline system in the US consists of about 340,000 kilometres of pipeline. The Canadian system operates 80,000 kilometres. These systems connect the major gas-producing basins with the principal US and Canadian market centres.

The natural gas industry in the US is made up almost entirely of private-sector companies. The transmission and distribution of gas have traditionally been treated as natural monopolies and are provided by utility companies operating under various state and Federal regulatory jurisdictions. Production, except for a unique twenty-four year period from 1954 to 1978, has always been treated as a competitive industry and has not been subject to utility rate regulation.

2.2. THE LIBERALIZATION PROCESS

Before the market was opened to competition, the gas delivery chain had a linear structure which was not dissimilar to the one which has evolved in Europe. E&P companies produced gas, sold it to inter-state pipeline companies, who in turn delivered it to the city gate and sold it to the Local Distribution Company (LDC), who then sold it to the end-user.

There have been five major policy turning points in Federal regulation of natural gas in the United States. Two of these were initiated by Congress, one by a Supreme Court interpretation of an earlier law, and two by major policy initiatives undertaken by FERC. They were:

- The Natural Gas Act of 1938
- The Supreme Court Phillips Decision – 1954
- The Natural Gas Policy Act of 1978 (NGPA)

The first of these is the underlying legislation under which the gas industry is regulated. The second, the 1954 Supreme Court decision, ushered in a period when wellhead natural gas prices were controlled by the Federal Government. The third, the NGPA, reversed the policy set in motion by the Supreme Court in 1954 and set the industry on the course of de-regulation. And the final series of FERC Orders now provide the basis for the presently restructured US gas industry.

2.3. THE CURRENT PRICING SYSTEM

The restructuring of the US gas industry by the various FERC Orders has created a highly liquid and transparent market for both gas as a commodity and for the transportation to move it to market.

The system has developed around a number of ‘hubs’ where pipeline interconnections bring gas flows together from different sources and re-distribute it to different market regions. Natural gas can be traded or priced at almost any location in North America.

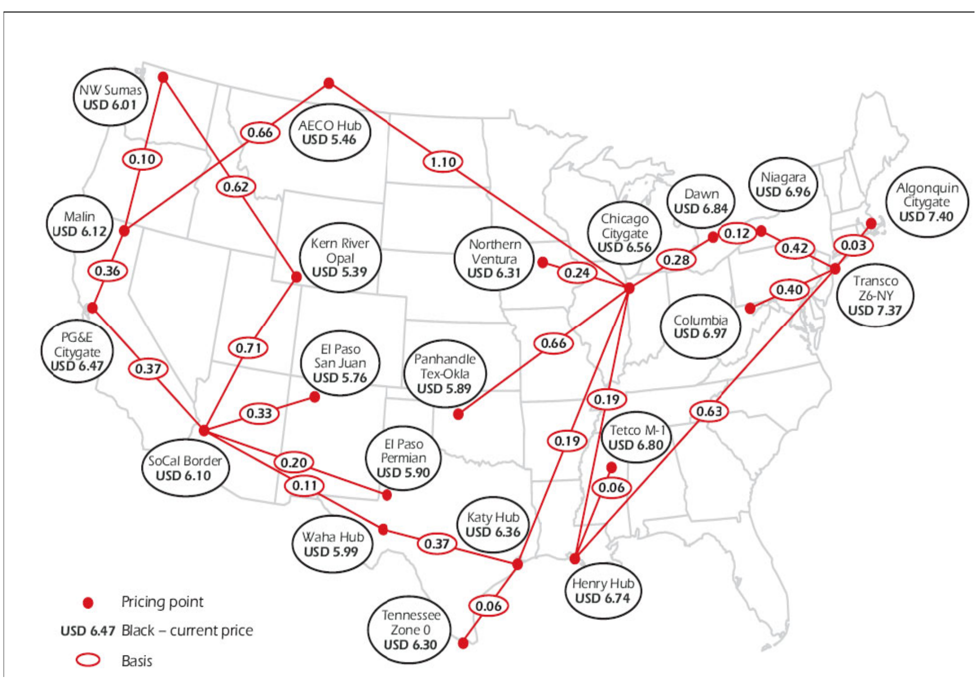
In North America there are 38 different hubs (29 in US and 9 in Canada). Trading hubs, whether a producing area hub located near a gas supply basin or a market area hub located near a market centre, are characterised by numerous market participants and access to services, such as balancing and title transfer, organised by the hub operator.

The most liquid hubs in North America are Henry Hub, located at the Gulf of Mexico in Louisiana, and NIT hub (NOVA Inventory Transfer) located in the western Canadian Sedimentary Basin in Alberta. Both hubs are located in the largest producing areas of their country and serve different markets. Prices at other hubs typically will be referenced as a differential between Henry Hub or NIT.

The national quotations for physical gas trading utilise Henry Hub as a reference point, much as the oil pipeline junction at Cushing, Oklahoma has become the reference point for the WTI (West Texas Intermediate) oil price quotation system. The Henry Hub is the reference point for trading in physicals and in papers, being the “underlying” of the New York Mercantile Exchange (NYMEX) futures.

The Henry Hub futures quotations have the advantage of complete transparency, since they are traded on an exchange.

Figure 1. US Major Trading Hubs and Spot Price ($/MMBtu), 2006



Source: IEA, 2007.

2.4. THE OPERATION OF THE SYSTEM

In the North American market, both the commodity and transportation capacity are freely traded. Shippers will typically line up capacity for the next transportation month. This makes for a very short-term – and frequently volatile – market.

When investment in new capacity is required, project sponsors will usually hold an 'open season' for potential shippers who are prepared to assume the obligation to cover 'demand charges' that are needed to recover the fixed charges on the investment. Thus the debt service on the investment is protected, not in the form of a take-or-pay contract for combined transportation and commodity, but in the form of a 'ship-or-pay' obligation.

2.5. CURRENT PRICE RELATIONSHIPS

As already mentioned, spot natural gas prices and individual month futures prices can be quite volatile and are affected by seasonality, but participants in the market make use of derivatives to manage price risk. The New York Mercantile Exchange (NYMEX) offers futures contracts for a seventy-two month period into the future, but the liquidity of the contract deteriorates rapidly for longer-term contract settlement dates

Market basis differentials relate the price at other hubs to the price at Henry Hub. Figure 1 compares the basis differentials for several market hubs – New York, Chicago and the California border. As is apparent, there is comparatively little variation between the Chicago price and Henry Hub, suggesting a limited price driving force to attract Gulf Coast supply to the upper Midwest.

Box - North American hubs: Henry Hub and NIT

The most liquid hubs in North America are Henry Hub, located at the Gulf of Mexico in Louisiana, and NIT hub (NOVA Inventory Transfer – NIT is often also referred to as Alberta hub or AECO hub) located in the western Canadian Sedimentary Basin in Alberta. Both hubs are located in the largest producing areas of their country and serve different markets. Prices at other hubs typically will be referenced as a differential between Henry Hub or NIT. From Henry Hub, most gas flows to eastern markets and gas from NIT is either used in western Canada or exported to the US. The following elements have made these hubs a success:

- *Connected to many large pipelines serving different markets (Henry Hub: 14 and NIT hub: 6)*
- *Large volume of gas flows (Gulf of Mexico: 20% of US production, western Canadian Sedimentary Basin: 80% of Canadian production). Henry Hub is also connected to the country's largest grouping of LNG regasification terminals*
- *Connected to high deliverability storage facilities*
- *Prices and other relevant information available. Delivery point of exchanges (Henry Hub: Nymex, NIT: NGX)*
- *Many different types of buyers and sellers*
- *Large daily volume of transactions*

2.6. USEFUL INSIGHTS FOR INDIA'S GAS MARKET

I - Conclusions and Useful insights for India's gas sector.

The restructuring of the US gas industry by the various FERC Orders has created a highly liquid and transparent market for both gas as a commodity and for the transportation to move it to market. Both the commodity and transportation capacity are freely traded. The national quotations for physical gas trading utilise Henry Hub as a reference point. Not only is Henry Hub the reference point for trading in physicals, but it has become the focus for the Henry Hub futures market trading on the New York Mercantile Exchange (NYMEX).

The physical spot market in North America is highly volatile, but participants in the market make use of derivatives to manage price risk.

The North American model, based on gas-to-gas competition and trading at hubs and between hubs, may serve as a useful reference for countries envisaging the introduction of an higher level of competition in their gas markets. Trading contracts and traded instruments evolved in the North America market, as well as a number of market-based solutions developed to address allocation and investment issues, deserve a careful study by energy policy makers and regulators. However, the sharp contrast between the structural conditions and the degree of development between the US and the Indian gas markets, make it hardly possible to borrow solutions and/or pricing mechanisms from the former for the latter.

3. THE UNITED KINGDOM

3.1. BRIEF DESCRIPTION OF THE UK GAS MARKET

The UK now has one of the most price-competitive gas industries in the world. Its transition from a government gas monopoly in 1986 to the liquid and competitive market today is a product of fortunate conditions and major policy initiatives.

The fortunate conditions were: on the supply side - reliance on domestic gas with an emerging surplus of low-cost gas from the Central North Sea that provided ample supply competition from traditional contracted supply, and, on the demand side – the need to expand the UK power sector in an environmentally friendly way by using gas-fired power plants in a restructured electricity market.

3.2. THE LIBERALISATION PROCESS

The key policy moves that led to the full liberalization of the UK gas market included:

- Privatising British Gas, the monopoly company
- Creating a regulatory body, Ofgas (later Ofgem) to oversee competition
- Restricting British Gas to 90% of the supply from new fields, thereby creating supplies for competitive sellers
- Requiring third-party access on the transition system to permit competitive suppliers to gain access to customers
- Requiring that British Gas free its customers of any obligation to purchase, thereby creating new buyers for competitive producers. This move was accomplished in a series of steps.

The original British Gas has now devolved into three separate corporate activities:

BG – formerly the parent company, now a major international gas company that is especially active in LNG; Centrica – the former marketing arm, now a successful independent gas marketer; TransCo – the former transmission company that manages the gas transportation operations and has been acquired by the National Grid, the major UK electricity transmission system.

These moves created substantial financial problems for Centrica, since it was still obligated on take-or-pay contracts for volumes of gas for which it no longer had sufficient customers. These financial problems were resolved by negotiations with the producers. However, the larger part of supplies landed at the beach of the UK under long-term contracts, part of it self-contracting and mainly linked to the newly developed price on the UK National Balancing Point (virtual hub)

The construction of the Interconnector, a pipeline linking Bacton in the UK with Zeebrugge in Belgium, initially served as an instrument for exports of UK gas to the Continent, under long-term contracts, although – compared to the prevailing model for gas imports to Continental Europe – the UK export contracts were for smaller volumes (each in the order of a few Bcm/year at most) and with a shorter term of 10-15 years. The Interconnector also created a basis for price interaction with the Continent by arbitrage, between a system characterised by short-term pricing in the UK and a continental system dependent on large import contracts based on the replacement value principle with a firm contractual delivery obligation.

The major transition of the UK – which occurred in 2004 – from a net gas exporter to a net gas importer, has created some uncertainty about the development of liquidity in the UK gas market and about the way in which future prices in the UK will interact with those of the Continent.

3.3. THE CURRENT PRICING SYSTEM

The UK gas market is in fact a series of quite different markets, requiring careful empirical examination in order to make sense of their articulation and the process of price formation. At the present time, four different markets can be distinguished: the retail market and three different "wholesale markets": the long-term bilateral contract market, the over-the-counter (OTC)[3] market and the on-the-day commodity market (OCM). These markets interact both with each other and with the International Commodity Exchange (ICE; former International Petroleum Exchange) futures market. Moreover both the long–term contract market and OTC market could themselves be seen more as containers for a series of different sub-markets (e.g. long-term contracts between the upstream and wholesalers or between upstream companies; OTC Day-ahead, OTC Year-out).

The OTC markets

Third party usage of British Gas' pipeline system increased from only 4 shippers at the end of 1990 to 15 shippers at the end of 1992. This was the decisive element that ignited spot or OTC trading. Originally, spot transactions were for gas injected at the Bacton entry point on the Norfolk coast; however, shortly after, delivery conditions were standardised and centred on the newly established National Balancing Point (NBP, 1996) – a virtual hub.

From that moment the contracts would be specified of delivery to the NBP, with two consequences that would allow a spectacular increase in gas volumes traded (foremost in terms of "paper trade" data). Firstly, prices thereby came to include entry capacity charges. Secondly, gas was liberated from the confines of specific projects or infrastructure routes.

Following on the establishment of the NBP, the next landmark of the OTC market development was the introduction of a standard contract. Because the OTC is not formally regulated, this was an example of "self-regulation".[4] Since the OTC has no single identifiable operator, this contract incorporates the responsibility of market participants to inform the transmission system operator (TSO, National Grid plc) about their trades, whether or not there is a firm intention to deliver gas. To be acceptable to the TSO buyer and seller nominations must be matched.

The OCM (balancing)

When Third Party Access in the UK became more formally organised in 1996, with the introduction of a "Network Code", which constitute a comprehensive agreement between the TSO and its customers, there had to be a mechanism whereby the TSO could acquire or dispose of gas in order to perform its role of residual system balancer and maintain the physical integrity and safety of the whole pipeline system. After an initial phase where a "flexibility system" – whose description is beyond the scope of this study was adopted, in October 1999 the so-called On-the-day Commodity Market (OCM). While the TSO retains responsibility for gas balancing, System Buy and System Sell prices (i.e. the price to add gas to the system and to take gas off the system, respectively) are set in a transparent marketplace, where shippers are able to trade with each other as well as with the TSO, thereby potentially reducing the need for the TSO to intervene.

Gas futures

[3] OTC is a term used to describe trades which are customised confidentially between the parties concerned – in contrast to open-market trades which are standardised and priced transparently.

[4] Its exact origins are difficult to pin down, however it is generally accepted that Enron and BP led the way, with the latter producing what would become an industry-standard contract in 1997.

A market in natural gas futures was established by the UK's International Commodity Exchange (former IPE) in 1997. The market operator is the ICE but the London Clearing House (LCH) acts as counterparty for all trades, thereby guaranteeing the financial performance of every contract up to closure or delivery. Five standard gas futures contracts are traded: Season (6 consecutive months in summer and winter), Quarter, Month, Balance of month (the number of days remaining in the current month), and Day.

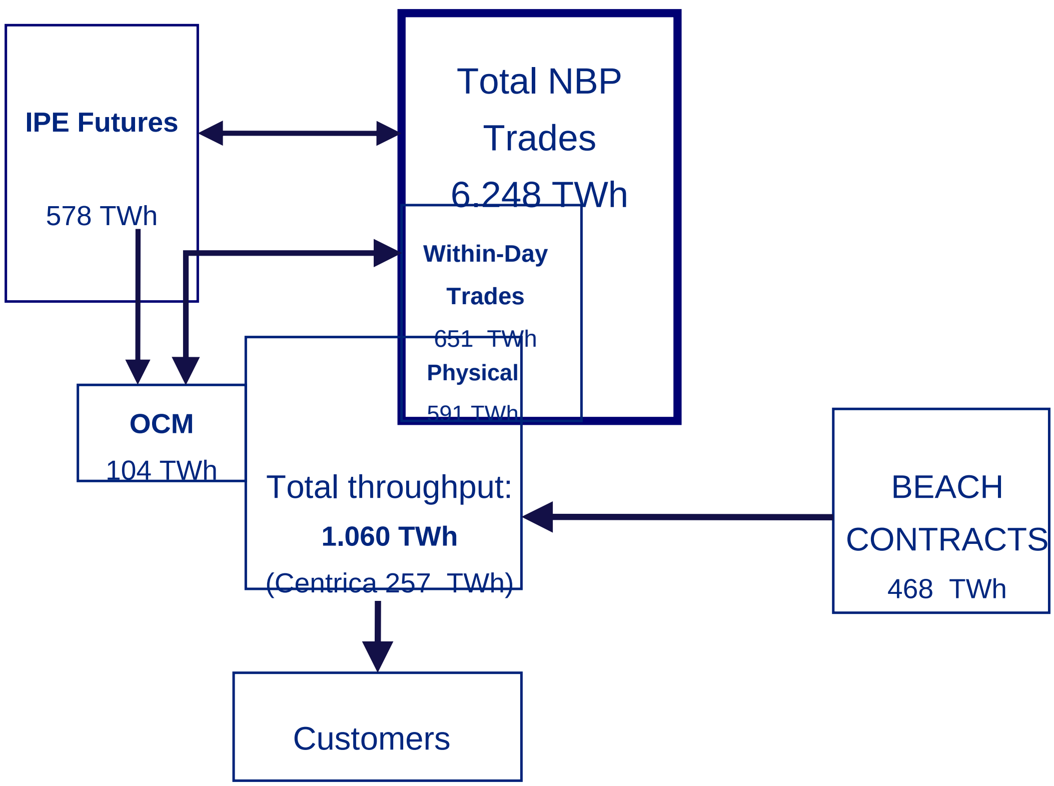
End-user market

The description of the UK's marketplaces is worthy to mention the retail market, which occupies the endpoint in the gas chain and does not present peculiar features with respect to traditional gas retail market, except for relatively high degrees of competition and switching.

3.4. The operation of the system: the wholesale markets brought together

The Figure 2 provides a representation of how the sizes of the NBP/OTC, OCM. ICE and beach contract markets look in relation to each other, and how the scale of paper trades looks in relation to physical trades. Particularly, deliveries to NBP are now greater than those represented by beach contracts and NBP trades for physical deliveries are less than 10% of the total trades (reflecting the "churn ratio"). ICE trades only cover about half throughput, while OCM balancing trades are dwarfed by "within-day" trading on the OTC. Centrica is responsible for nearly a quarter of throughput.

Figure 2. UK Market Structure (volumes data 2006)



3.5. Useful insights for India's gas sector

II – Conclusions and Useful insights for India's gas sector.

The UK negotiated the transition from government monopoly control of its gas industry to a liquid commodity market. The UK spot gas market is now one of the most liquid markets in the world and is the most liquid in Europe, with roughly 70 active players. However, prices still largely follow the trend of competing fuels (clearing price coal / heavy fuel oil in summer and gas oil / liquids in winter) and after the surplus gas supply disappears prices rise substantially.

As in the case of the North American market, the complexities of the UK's wholesale market do not seem to provide pricing mechanisms that can be feasibly transposed to the Indian gas market.

4. CONTINENTAL EUROPE

The development of the gas industry in Continental West Europe has been characterised by imports from super-giant fields, starting with the development of the Groningen field.

In order to maximise the rent income from the Groningen field for the Dutch state, the Dutch government, together with Exxon and Shell, developed the concept of replacement, or market value pricing (which was also applied domestically), and the concept of long-term contracts with a minimum pay based on a netback / replacement value pricing, with regular review possibilities to adjust pricing to the originally sought balance.

The concept of long-term contracts aimed at maximising the rent income of the exporting state, while keeping the gas marketable, or in other words the seller (the exporting country) was taking risks and chances of price development via the replacement value pricing concept, while the buyer was taking the obligation to market a defined volume via the minimum take-or-pay obligation against earning a satisfactory margin.

The Dutch export contracts served as a point of reference for most gas export contracts to Continental Europe which followed over the next four decades.

Changes in market conditions were reflected in the new contracts concluded and by regular price reviews for existing contracts. Adaptations to changed circumstances happened by modifying the original (very large) long-term contracts by changing the price formula to reflect the development in the competitive situation of gas, mainly by increasing the share of gas oil, but also by including elements to reflect the changed role of gas in power generation and later the role of gas-to-gas competition. As a result the currently applied price formulas for imported gas follow similar patterns, as was shown by the report of the Energy Sector Inquiry by the European Commission's DG COMP, published in January 2007.

While EU gas market reforms changed the regulatory framework since the end of the 1990s, long-term import contracts persisted as the dominant import arrangement, now complemented by some imports, on a short-term basis from the UK and by some spot LNG mainly to Belgium. Except for the adaptation of the pricing formula to new competitive situations, new import projects kept with the principles of long-term contracts, with some modifications as to the size of volumes, term and more flexibility regarding the delivery point.

4.1. BRIEF DESCRIPTION OF THE EUROPEAN CONTINENTAL GAS MARKETS

Natural gas consumption in EU member states was around 445 mtoe in 2008 and is expected to increase to about 625 mtoe in 2030, which is an increase of 43%. The share of natural gas in the European primary energy demand will rise from 23,9% in 2005 to 29.9% in 2030 (18% in 1990). At 60% of the total demand increase, most of the growth will come from power generation.

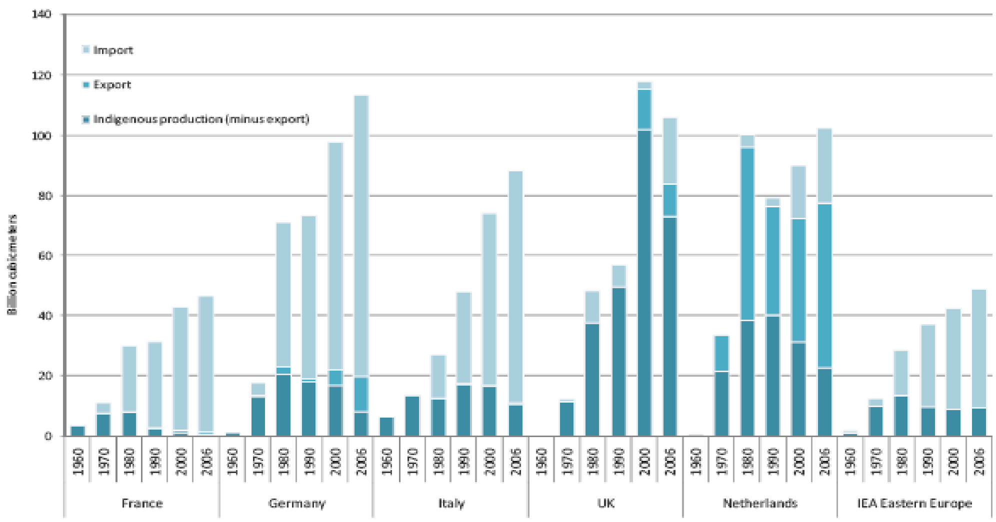
In the residential and commercial sector, gas consumption has steadily increased in line with the expansion of the infrastructure and the associated rise in the number of gas users. Over the last 15 years, gas consumption has seen a 2.8% growth p.a. to 175 mtoe. Gas currently holds a market share of approx. 35 %, which makes it the market leader in this sector.

Gas currently accounts for 33 % of industrial final energy consumption (excluding industrial power stations) and is thus a major source of energy in this market, too.

The development of the modern natural gas industry in the Western parts of Europe started with the discovery of the Groningen field in 1959. Further drilling proved it to be a super-giant field. It was clear that its gas could not solely be consumed in the Netherlands, but that, in order to valorise the gas reserves of the field, part of its production had to be exported. Groningen gas was the first large gas-export project worldwide and became the reference case for all other gas imports into Continental Europe.

After the first oil shock, Western economies were given new impetus to diversify their energy mix. Although the United States in particular opposed European dependence on Soviet Union gas, the huge Siberian gas fields were able to provide Europe with a non-OPEC source of energy. A compromise was agreed whereby the Europeans would restrict their dependence on Soviet Union to 30%, and the development of Norway's Troll field would be promoted as a counterweight to Russian influence.

Figure 3. Europe's dependency on long term imports



Source: Eurogas, 2008

4.2. *THE LIBERALIZATION PROCESS: 1998 – 2009*

The aim to build a single market for gas and electricity is a principle embedded in the creation of the European Union – the EC Treaty mandates the building of a common market including energy (Treaty of Rome 1957, Single European Treaty 1985, Treaty of Maastricht 1992). Making the energy sector in Europe competitive and more efficient was viewed as part of the response to growing concerns on the competitiveness of European industries in globalising markets.

Negotiations between the EU authorities, the member states and the market stakeholders during the 1990s culminated in an Electricity Directive (96/92/EC) and, two years later, in a Gas Directive (98/30/EC) introducing a first set of common rules for the EU energy markets. On natural gas, the new legal framework was aimed at opening the gas networks to third parties. This was to be achieved through unbundling of the vertically integrated historical gas operators, thus allowing competition for supplies and customers within the natural monopoly network. The European Commission encouraged the industrial re-organisation within each country to be supervised by an independent regulatory authority, but this was not mandated.

Initially, the opening to competition granted the choice of supplier to big gas customers such as power plants and big industrial facilities. A level of eligibility was to be defined by the member states such that at least 20% of the national market was free to choose suppliers when the Directive entered in force, (the level was to be progressively increased). The eligible customers were free to contract their gas supply with the supplier of their choice, the latter being authorised to ship gas through the existing network with the Third Party Access (TPA) provision of the Directive.

The member states could choose different approaches to implement the opening to competition process (negotiated or regulated TPA, accounting unbundling, legal unbundling or complete separation, ex-ante or ex-post regulation of the market), but overall equivalent economic results and market opening were required between the national markets.

Even before the implementation of the first Gas Directive there was already a push to accelerate gas and electricity liberalisation. The European Council, held in Lisbon in March 2000, requested that the Commission undertake further steps towards the completion of the internal energy market. The EU Council at Barcelona in March 2002 decided on full market opening for industrial gas consumers in 2004 while total market opening was intended for 2005. It launched the preparation of a new legislation to implement these decisions. A year later, the second Gas Directive was adopted (2003/55/EC). Concomitant to a second Electricity Directive (2003/54/EC), the new EU gas law mandated regulated TPA as the basic rule (for all existing infrastructure) as well as moving the level of unbundling of TSOs to the level of legal separation (e.g. regulated activities under the responsibility of separate entities). The role of independent regulators was also reinforced.

The 6th benchmarking report was issued in January 2007 and provided a general overview of the future energy policy of the EU. It envisaged a "third package" of legislative proposals for the European gas and electricity markets. The rationale of this third package is the integration of the energy and the environment objectives of the EU through the use of market based environmental and other measures.

The EU Commission proposed ambitious and far-ranging measures such as complete de-integration of the gas operators through ownership unbundling and further institutions to back-up the creation of an integrated EU gas market (European regulatory agency).

Third Energy Package.

On April 22, 2009, the "Third Energy Package", consisting of 2 Directives and 3 Regulations on electricity and gas, has received final approval (2nd reading) from the European Parliament, according to the compromise agreed with the Council Presidency. The package was approved by the European Council in June 2009.

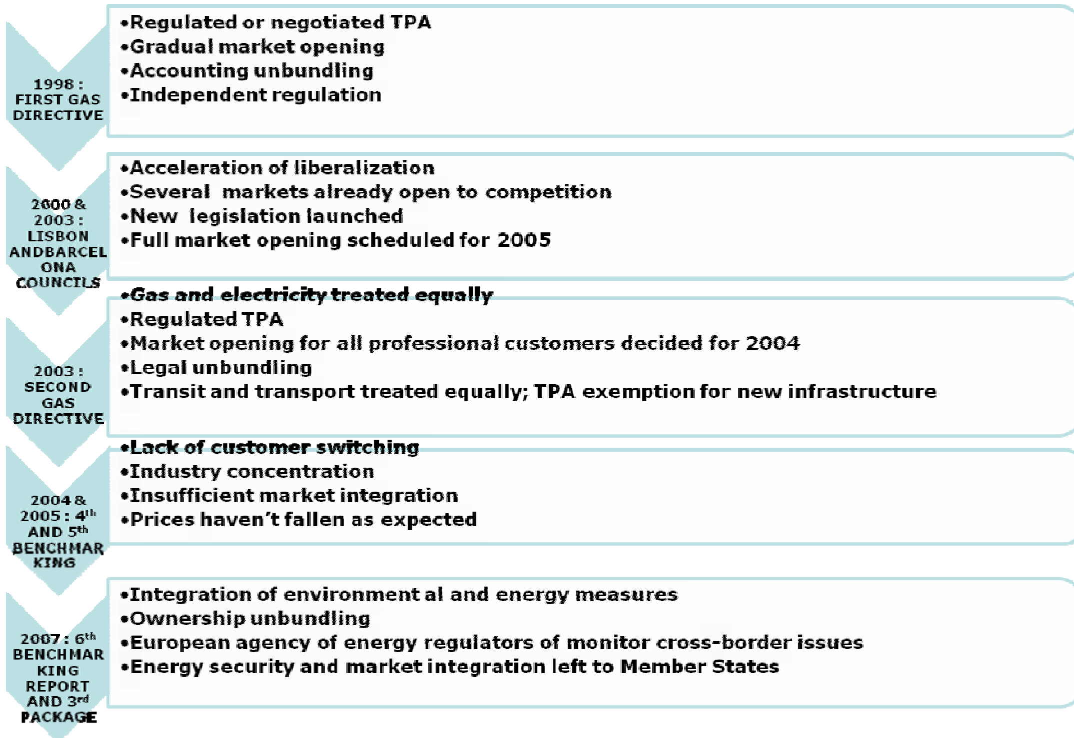
The revised package details rules for unbundling and the responsibilities of the new European Agency for the Cooperation of Energy Regulators (ACER) and the new European Network for Transmission System Operators (ENTSO) for both gas and power. The shape of the European energy industry in the coming years will be heavily influenced by the interaction of these new bodies with national regulators and the European Commission.

• Unbundling: the package leaves three unbundling options on the table, with member states able to choose their preferred form of separation of transmission and supply: ownership unbundling, independent system operator (ISO), and ITO—for both gas and power. According to the ITO model, the "third way", generation/supply companies may still own and control transmission operators, although separate companies under common ownership must be set up to hold and operate the assets.

• ACER: the package creates a new Europe-wide coordinating and advisory body made up of national regulators with powers over cross-border transmission

• ENTSO: the new Europe-wide group of transmission operators for gas and power will have responsibility for developing and implementing network codes for cross-border transmission within a framework set down by the Commission and ACER.

Figure 4. Chronology of EU liberalization



4.3. THE CURRENT PRICING SYSTEM

Historically, gas in Europe has been sold indexed to the price of certain alternative fuels. Such a pricing mechanism is markedly different from the one found in traded gas markets, where price is determined solely by gas demand and supply at market areas or "hubs".

While EU gas market reforms changed the regulatory framework since the end of the 1990s, long-term import contracts persisted as the dominant import arrangement, now complemented by some imports, on a short-term basis from the UK and by some spot LNG mainly to Belgium. Except for the adaptation of the pricing formula to new competitive situations, new import projects kept with the principles of long-term contracts, with some modifications as to the size of volumes, term and more flexibility regarding the delivery point.

The major elements incorporated in the long-term oil linked gas are:

- long-term supply obligation balanced by a long-term offtake obligation (take-or-pay clause)
- pricing based on the concept of netback value calculated on the basis of the value of competing energies backed to the border of the buyer's country by deducting the costs of transportation and distribution of the buyer (see next 2 slides)
- possibility to review at regular intervals (typically three years) the price conditions in order to adapt them under defined criteria to changed circumstances in the market

This concept ensures a reliable sales volume for the seller at prices as close as possible to what can be sold in competition with other fuels in the market (in fact, netback calculated back to the wellhead provides for the maximum specific rent which can be obtained from the market). On the other hand, it allows marketing of the gas while offering a reasonable margin to the buyer. Risks related to price movements of the competing energies are mainly carried by the producing country. In this way, the seller takes the price risk, the buyer the volume risk linked to marketing.

The vast majority of continental Europe gas imports (more than 250 bcm in 2008) is still based on the Groningen's concept. The prominent examples are: the first exports from the USSR (SGE I-III), Algerian exports to Italy via the Transmed pipeline, Algerian LNG to France and Belgium, and later Algerian pipeline exports to Spain and Portugal via the Magreb pipeline, the Norwegian Ekofisk and Statpipe contracts,69 additional Russian exports under the SGE IV project, the Troll sales to Germany, the Netherlands, Belgium, France, Austria and Spain and later Norwegian exports via the GFU to VNG in East Germany and to the Czech Republic, Nigerian LNG, and later UK exports to the Continent.

In turn, gas is sold in the domestic markets according to pricing formulas that "reflect" in their structure the key features of the import ones.

Long-term import contracts[5]

Box Stylised Price Formula of Long-term Contracts

Pm = Po + 0.60 x 0.80 x 0.0078 x (LFOm - LFOo) +

0.40 x 0.90 x 0.0076 x (HFOm - HFOo)

(i) The gas price Pm: applicable during the month m is a function of:

- *the starting gas price Po*
- *and the price development of competing fuels compared to the reference month, in this example: Light Fuel Oil (LFO) and Heavy Fuel Oil (HFO)*

(ii) 0.60 and 0.40 are shares of gas market segments competing with respective fuels (no dimension):

- *Light Fuel oil / Heavy Fuel Oil*
- *These shares will be different from the shares of these fuels in total energy use; e.g., the share of heavy fuels used in most European markets is now rather small, however, it remains the best available alternative for most of the gas used for industrial purposes*

(iii) 0.80 and 0.90: Pass through factors (no dimension):

- *Sharing risk and reward of the price development between seller and buyer*
- *Most of risk and reward for the seller (0.80/0.90)*
- *May be different for different fuels*

(iv) 0.0078 and 0.0076: Technical equivalence factors to convert the units of prices for fuel into units of gas price. In this example:

- *Gas in kWh (GCV), Fuel oil in t*
- *Dimension: Euro cts / kWh / Euro / t*

(v) Competing Fuels:

- *Quotations reflecting the market*
- *With or without taxes on competing fuels*
- *Time lag and Reference Period to be defined*

LFO: Price of Light Fuel oil

LFOo: Price of Light Fuel Oil for starting month o

LFOm: Price of Light Fuel Oil resulting for month m (may refer to an average value of previous months depending on reference period and time lag agreed)

LFO is usually reflecting competition for medium and smaller customers whose alternative is using Light Fuel Oil (typically small industry, commercial, administration, households).

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[5] This box is based on ESMAP (Joint UNDP / World Bank Energy Sector Management Assistance Programme), Long-term Gas Contracts: Principles and Applications, ESMAP Report No 152/93 (January 1993).

It has to be noticed that the concept of replacement value, combined for export contracts with the concept of a netback price, results in different netback values at the exporting country's border for different customers. In addition, different transportation costs to different customers imply different netback values earned by the exporter at its border, even if the replacement value at the border of the customers would be the same.

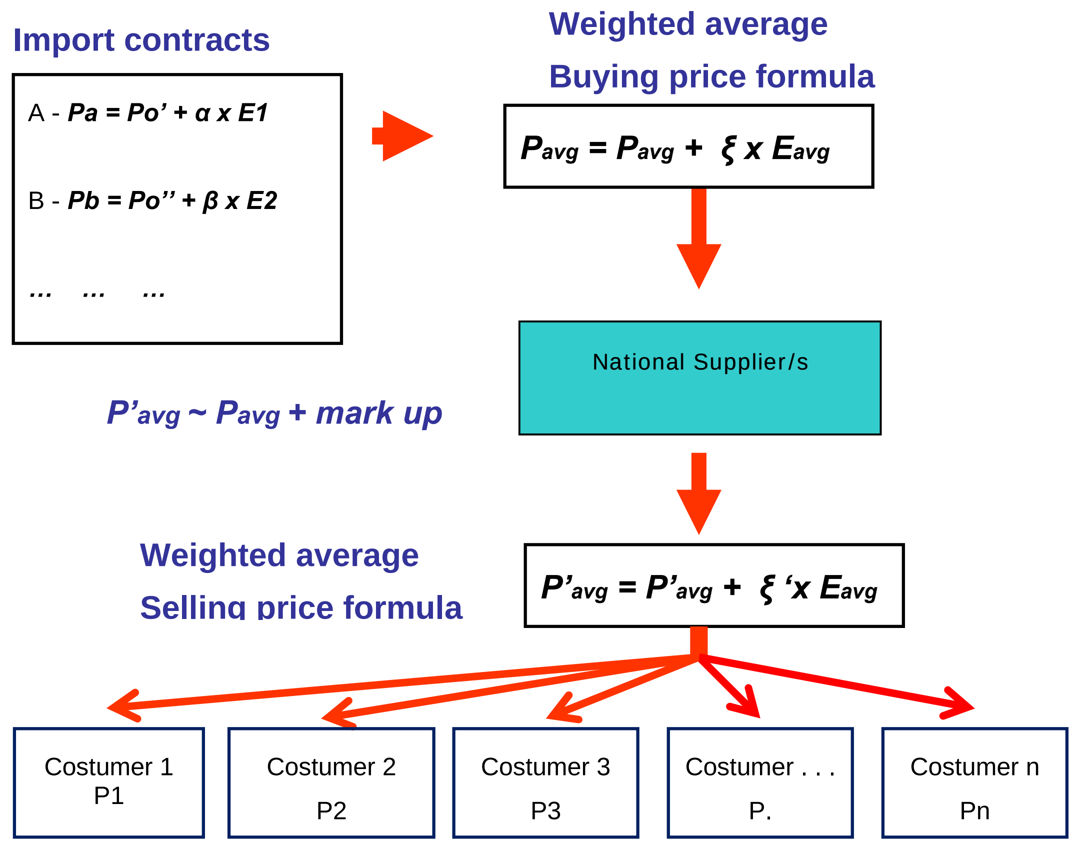
A special king of "pooling price mechanism"

Historically, key features of long-term import contracts (e.g. basket indexation, elasticity to energy price changes) have been largely "mirrored" in the domestic wholesale and retail supply contracts. This means that the (dominant) national suppliers, while defining the overall structure of their selling portfolio, have usually designed a range of selling price formulas that, on average, reproduce the indexation and the cost level of their buying portfolio. In this way a number of key results are achieved, in particular: 1) the national supplier hedges its overall portfolio (i.e. its price risk exposure is largely reduced; 2) this sort of pooling price mechanism allows to have a gas price substantially uniform, by consumer category, across the country (i.e. not directly linked to the cost of any specific long-term supply contract of the supplier or its direct production).

After the liberalisation, the new entrants have largely adopted this conventional rule, often taking as a reference the price formulas of the incumbent and offering discounts on them.

The logic of this pricing system is illustrated by Figure 5.

Figure 5. Stylized conventional “pricing system” for end-user sales in Continental Europe markets



In other words, the “fuel component” of the selling price formulas tend to reproduce, in overall aggregation and to the extent possible, the weighted average cost (plus a mark-up) of the supply portfolio of their supplier (particularly in the case of the incumbent). This could be seen as a sort of “pooling price” mechanism.

4.4. CURRENT PRICE RELATIONSHIPS: HYBRID MARKETS

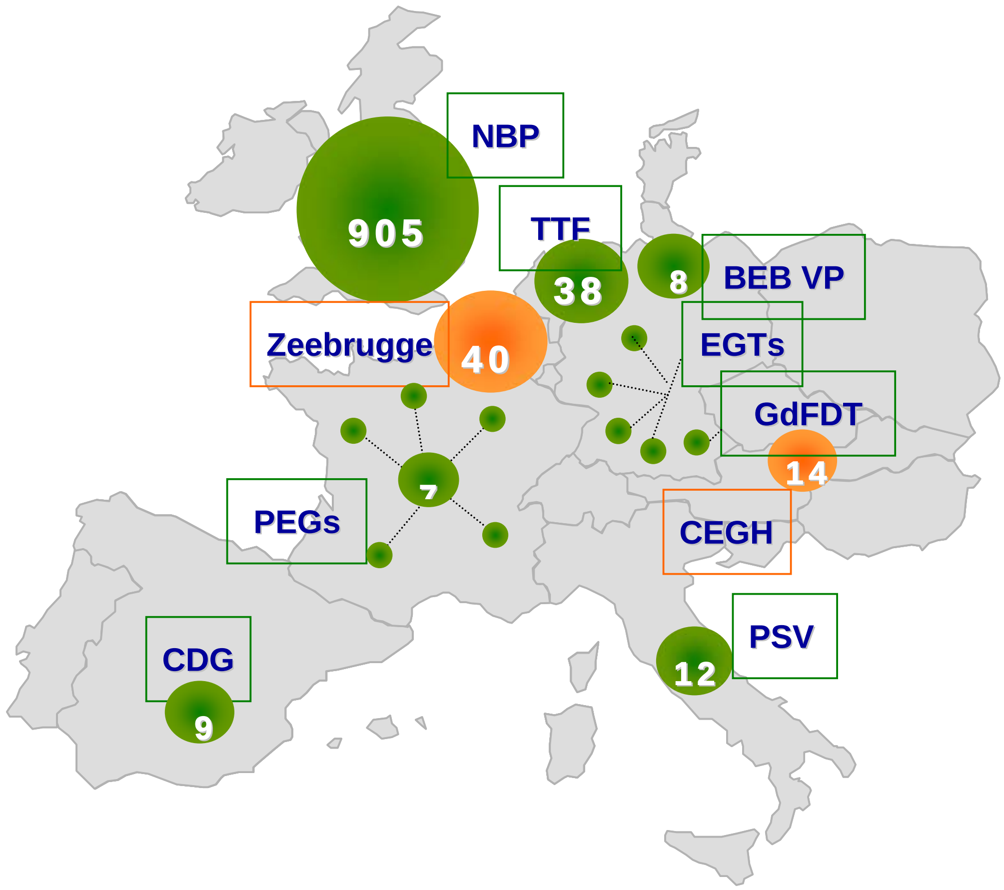
On the continent oil indexed contracts still dominate, with hardly any hub-priced long-term contracts having been signed. However, a number of short or medium contracts do exist which are either fully or partially hub-priced; in fact, starting from mid-90s, a number of gas trading have been created by regulation or the industry.

Where gas priced markets co-exist with long-term fuel substitute contracts, there will be a competition between the two contracted sources of gas. If there is a well functioning, deep and liquid hub, then it is possible the hub price will influence the long-term contract price. For example, in the case of the United Kingdom, in a cold winter, we see the interaction of large long-term contracts with a hub-based market in a supply constrained environment.

This same logic dictates that with time even the longer-term contracts in Europe will probably be affected by the existence of the traded markets, as the price level of these will have to be inline with the expectations of the level of future spot prices at the hubs.

From the perspective of a producer, who is supplying to the wholesale market, on a traditional oil indexed contract, the situation is different. The industry has long argued that the long-term gas will be priced by inter-fuel competition. If this is a fact, then a supplier should be indifferent as to whether he prices his gas at a hub or at an alternative fuel. Furthermore, there could be additional benefits to the producers of supplying at a hub namely to avoid the opportunity cost described in the previous paragraph, in the short term. However, the lack of liquid hubs in continental Europe currently discourages producers from selling at that price. Moreover, the industry has operated on oil-based prices for more than thirty years and views such a major change in business practice as a huge risk to its business sustainability. Finally, in the current environment, oil prices are at historical high levels. This removes the incentive to the producer to try a different pricing system.

Figure 6. Major European Gas Hubs. Total traded volumes (bcm), 2008



Notional hub /Balancing Point

Physical hub

Source: Mercados research

4.5. TWO TYPICAL CONTINENTAL EUROPEAN MARKETS: ITALY AND FRANCE

4.5.1 Italy

The partially state-owned Eni has traditionally dominated the Italian gas market through its subsidiaries; the former Snam in the case of midstream and downstream gas activities and Agip (Eni's E&P division) in upstream activities. Even though liberalisation has changed the organisation of the sector, Eni still holds a dominant position.

The Italian mid and downstream gas sector is regulated by an independent body – the "Autorità per l'Energia Elettrica e il Gas" (AEEG). AEEG is responsible for ensuring access to the network is competitive and transparent, setting TPA tariffs, setting tariffs for captive consumers and generally overseeing energy sector operators. The Italian regulator has been firmly in favour of introducing a stricter liberalisation regime than required by the EU directive

The key aspects of the law were as follows:

• Regulated TPA system for both pipelines and storage;

• Transportation and storage activities were unbundled into separate companies by January 2002;

• Since January 2003, all consumers have been free to choose supplier;

• A limit has been placed on the volume of gas any one company may produce and import: 61% in 2009;

• A ceiling of 40% of total sales to final consumers has also been introduced for sales of any one company.

The spot market trade at the balancing point 'Punto di Scambio Virtuale' (PSV) is growing in importance, having been introduced in October 2003 to facilitate short term deals between shippers. In 2008 volumes traded at the PSV accounted for about 28% of the total. Most deals on the PSV are of a back-to-back nature, with very little players trading for speculative purposes. Parties transact to adjust their respective positions. Most new entrants, including foreign players, trade on the PSV or use it as a convenient point to transact one-year contracts as opposed to spot volume. There is still no spot price transparency at the PSV as transactions are not priced and are all bilateral. Currently, the only wholesale gas price transparency in Italy is in the shape of the Eni gas release auction.

4.5.1.a Italy's current pricing system

Till July 2007 AEEG was responsible for establishing (maximum) gas prices for residential and commercial customers and also supervises negotiated prices for other consumers. Since then AEEG only set a "reference price", which the retail supplier must include within the prices/pricing formulas they offer to the clients.

For industrial customers, the price is usually based on a volume charge and maximum demand charge and depends on the customer indicating to the supplier the maximum daily volume and also the total expected volume for the year:

- the volume charge is indexed to gas-oil, crude oil and heavy fuel-oil prices (mirroring the type of indexation and elasticity to energy price changes which is incorporated in the long-term import contracts). There are various volume discounts that can be applied to this part of the price;
- the demand element of the tariff also has a base charge that is indexed. The indexation is annual and is based on the movement in wages and in PPI.

4.5.2 France

The gas industry in France is dominated by Gaz de France (GdF), which directly or indirectly operates at all market levels – imports/wholesale, transmission and distribution, and supply. For the bulk of its supplies, the French gas market relies on long-term contracts between incumbent suppliers (predominantly GdF and Total, who account for 95% of imports) and national companies from producing countries. The share of alternative suppliers (such as Tegaz and local distributors) in imports is on the rise, while there are also 12 foreign companies operating in the wholesale market. There are two TSOs in France, one of which is owned by GdF and operates around 88%

of the French transmission network, while the other is owned by Total and operates 12% of the network. At the distribution/supply level, there are 22 DSOs, with GdF again dominating this part of the market (96%). There are also 11 suppliers currently active in the retail market, which are independent of network companies.

The deregulation of the French gas market took place in several stages:

- From August 2000, all sites with an annual gas consumption over 237 GWh and all electricity generators or simultaneous electricity and heat generators whatever their annual consumption level became eligible
- From August 2003, all sites with an annual gas consumption over 83 GWh became eligible
- From July 2004, all companies and local government agencies became eligible
- From July 2007, all customers became eligible, including residential customers.

4.5.2.a France's current pricing system

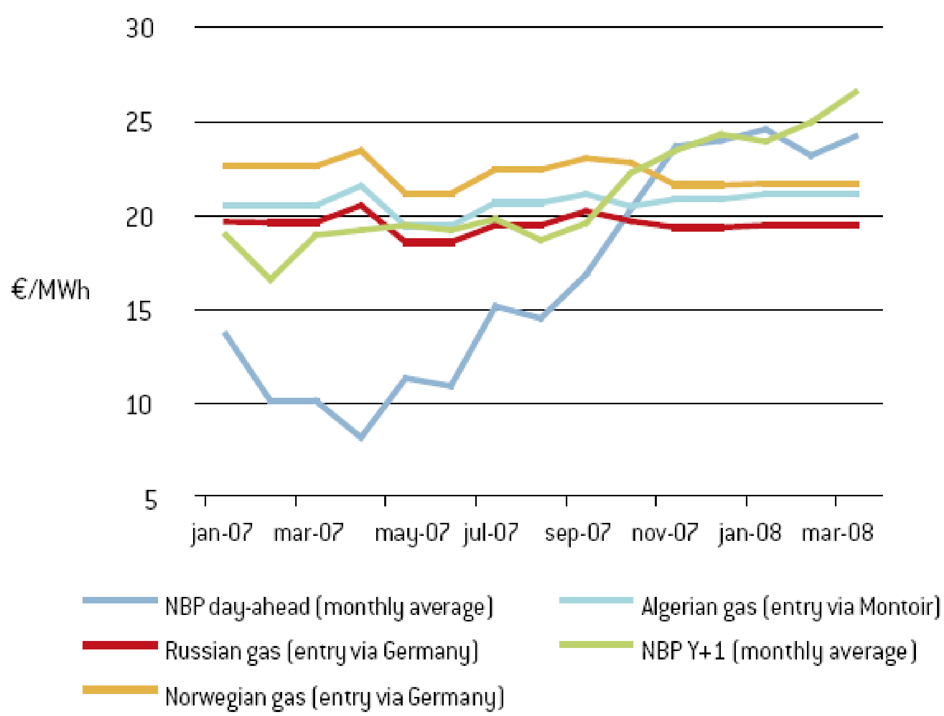
The pronounced vertical integration and the absence of any new programme of gas release (after that of 2005) prevents the French market becoming more liquid. As a consequence, the vast majority transactions on the French wholesale market are bilateral contracts with no intermediary.

France currently has 3 balancing points (PEGs, Point d'Echange de Gaz) which perform the role of trading hubs, 2 belonging to GRTgaz (transportation subsidiary of Gaz de France) and one belonging to TIGF (transportation subsidiary of Total). Volumes exchanged at PEGs among traders, although have been steadily increasing for the last five years, are still marginal compared to the size of the physical market (less than 10% of national consumption in 2008).

In the French market, there are essentially two types of end-user contracts:

- Contracts under regulated retail tariffs, only proposed by incumbent suppliers (Gaz de France, Tegaz and the 22 LDCs) in their respective zones. An incumbent supplier's zone is defined by a concession or or regulation applying to the services of state-run distribution companies;
- Market-price contracts, proposed by incumbent suppliers and alternative suppliers, who are free to set the price. Market-based contracts vary according to customer segment. They usually reflect the type of indexation and elasticity to energy price changes which is incorporated in the long-term contracts.

Figure 7. Long-term contract prices vs NBP prices



Source: Platts

4.6. USEFUL INSIGHTS FOR INDIA'S GAS SECTOR

III - Conclusions and Useful insights for India's gas sector.

The development of the gas industry in Western Europe was characterised by early imports, driven by super-giant fields. The concept of long-term minimum-pay contracts, with pricing based on replacement value, proved to be a successful concept for an increasing penetration of gas in the energy sector in the Western part of Continental Europe. Key features (e.g. indexation basket, elasticity to energy price changes) of long-term import contracts have been largely "reproduced" in the domestic wholesale and retail supply contracts.

The pricing system traditionally adopted by incumbent suppliers in Continental Europe markets (described in section 4.3), *mutatis mutandi*, is surely of interest for India's intention of establishing a "pooling price mechanisms" for its LNG imports.

VIII POOLING OF TRANSPORTATION TARIFFS

Our Terms of Reference require us to consider the option of pooling of transportation tariffs along with the commodity costs. The transportation tariff regime in India is based on the use of various pipeline segments for point to point transportation of gas. In effect it follows the "contract path" method. Any use of a pipeline segment up to 300 Km along the contract path is charged a certain tariff determined by the PNGRB for the particular pipeline. The following example illustrates the tariff mechanism along a 3 pipeline system along the contract path.

Illustration: Transportation along 3 pipeline systems from one point to another at a distance of 1600 kms

Illustration

Pipeline System	Tariff (Rs. Per MSCM per 300 km)	Distance traversed	Segments used	Total tariff
1	1000	500	2	2000
2	750	400	2	1500
3	750	700	3	2250

The key argument in favour of tariff pooling is that the transportation tariff discriminates against the customers who are located at a distance from the gas source and this result in underdevelopment of markets at potential consumption points.

While we appreciate the motive for pooling of transportation charges, we do not favour the same for several economic and practical reasons:

- **Pooling of transportation charges will reduce the economic signals and result in misallocation of economic resources**: Since only the gas tariffs would be pooled while the other economic inputs would not be, the pooling would result in wrong siting decisions, causing an economic loss to the country;
- **Pooling could result in stranded assets**: Once the pooling mechanism is done away with it, the manufacturing assets established would become uncompetitive. It would also result in stranding of the pipeline investments as a consequence. Since pooling is only a transition mechanism this would be inadvisable;
- **Gas transportation charges are a relatively small component of the delivered costs: The** transportation costs are typically only about 20 – 25% of the costs. Hence commodity pooling has a far greater impact;

Gas pooling as a policy would result in a situation like "freight equalisation", which imposed very high economic costs on the country, and eventually had to be done away with.

We however suggest deepening of the pipeline network across the country, if required through mandate to ensure that the commodity is reached across the country. If necessary, till the volumes build up, a framework akin to Access Deficit Charge (ADC) in telecommunications could be introduced for gas. This would help operators recoup their investments without compromising the price signals.

We also believe that as the pipeline system grows and a network develops, there is a need to move away from the contract path method to an alternative framework that relates to the actual physical distance traversed by the gas. A contract path method is extremely inefficient in a meshed network. An alternative could be the Point of Connection tariff method, which is commonly used in networked transportation systems.

As regard the transmission pricing system and pooling of the tariffs, in the large countries comparable to India, we have seen no evidence of transmission price pooling. In the United States, all pipelines have distinct tariffs. Canada follows a similar approach. Australian pipeline tariffs are re-set periodically following Performance Based Regulation (PBR) frameworks for each pipeline system. In China the transportation tariff is principally determined by the distance. The following table highlights the distance based slab for a distance of 500 KM. The current tariffs are fixed for each pipeline thus reflecting the construction cost.

Table 8.1: Transportation tariff by distance

Distance (KM)	(*CNY/1000 Cu.Mtr)	($/1000 Cu. Mtr)	($/MMBTU)
<50	36	5.19	0.14
50-100	41	5.91	0.16
101-200	47	6.77	0.18
201-250	58	8.35	0.22
251-300	63	9.07	0.24
301- 350	68	9.79	0.26
351-400	74	10.66	0.28
401-450	79	11.38	0.30
451-500	85	12.24	0.32

Source: CNPC

* Yuan (Currency of China)

In none of the countries analysed there is any evidence of pooling of transportation tariff. Each pipeline or pipeline system has a unique tariff, that is either common or is segmented. Most of the developed countries have Open Access Transmission Tariff for the pipeline systems, and these tariffs are notified and applied on non-discriminatory basis.

IX RECOMMENDATIONS

It is important to note Indian gas market needs a rational gas pricing mechanism to encourage efficient consumption and development of natural gas infrastructure, while preserving the incentives to gas suppliers. Gas price pooling (either based on cost pooling or bid based pooling) is desirable for all the sectors consuming gas in order to bring in price stability at the individual consumer level. However, the analysis conducted in the section V of the report illustrate that Power and Fertilizer being the most vulnerable sectors, it is imperative for the Power and Fertilizer sectors to have a stable (within a range) gas price. Accordingly the following are recommended:

1. Price pools should be formed for power and fertiliser customers. We recommend separate pools for the two sectors to avoid cross subsidies between the customer groups and administration issues that a combined pool would present;
2. The pools should be notified consequent to a policy issued by the GoI. The notification should spell out the guidelines for pool operation in sufficient detail, and should also provide for tenure for the pool. The pool can be disbanded or extended upon a specific review on completion of the term. Considering the market realities we recommend a 4-5 year term for the pool;
3. The policy should notify a pool operator. We believe that GAIL as an existing operator of the pipeline system (and also with prior experience of pooling of RLNG) would be well placed to operate the pool. However the pool operation would have to be done on an arms length basis with suitable functional separation within the organisation. The design of the pool should be undertaken on the basis of minimisation of structures, costs and complexities;
4. A detailed set of pool rules should be drawn up and such rules should be notified by the GoI after due consultation. The limits of operations of the pool should be clearly set out, including the range of acceptable pool prices and corresponding quantities to be introduced. Detailed operating codes would also need to be drawn up;
5. All existing contracts for the sectors identified for pooling should be modified or novated to the pool as per the pool rules. This would require the pool operator to develop standard contracts;
6. The pool should feature the necessary institutional structures and governance arrangements discussed earlier in this report. A separate analysis of these arrangements is suggested consequent to acceptance of the recommendations of this report;

As mentioned, the pools are recommended for the power and fertiliser industries only. This leaves adequate room for an alternate market to develop for other industries and even for customers of the power and fertiliser sector (particularly the former), who may not wish to be a part of the pool. This would facilitate price discovery for new gas supplies, and the pooling arrangements would not be a limiting factor for development of the industry beyond the limits that the pool can serve within its rules. This would also provide comfort to new gas suppliers who wish to supply to such industries.

It is important to note that the benefits of cost pooling are not necessarily restricted to the power and fertiliser sectors only. However the benefits of central pooling in the other sectors on the lines proposed is more complex on account of the large number of consumers with small volumes, since this would militate against the objective of keeping the pool administration set up and costs to a minimum. For the other sectors such as sponge iron, petrochemicals, CGD and other small customers pooling can be done at the gas supplier’s level. In the present scenario the gas consumers source gas from various sources and pool it at the individual company level. Our analysis shows that in the international markets such as Italy and France where mostly the supply is based on contracts the gas supply company pools the gas from various sources and supplies it to the customers at a common price to all the end consumers. As we have mentioned in the report, we do not recommend pooling of transportation costs since this distorts the basic economic price signals derived from the location of the customer vis a vis the resource. However we do recommend the development of a robust gas transportation system across the country based on a policy or legislative mandate. In the initial years when the utilisation is low on such pipelines, the policy framework should place limits on the pipeline charges. Deficits if any can be made good through mechanisms like Access Deficit Charges (ADC) as prevalent in the telecommunications sector.

Finally we recommend the creation of a roadmap for migration to competitive wholesale markets for gas, which would typically be through bid based pools, and feature a large number of independent shippers. It is important to note that such mechanisms could coexist with cost based pools and also long term contracts for gas supply. This would result in the emergence of a vibrant gas market that could attract new gas suppliers willing to supply for various contract tenures, and would provide a strong signal for emergence of gas trading hubs at key despatch/aggregation points in the country.

ANNEXURE - GAS BASED POWER PLANTS

Companies (Existing)	Installed Capacity (MW)	Nature of Sales Portfolio[6]	Private/Govt.	Gas Requirment (MMSCMD)
Auriaya Gas Power Station	204.00	Long Term	G	0.82
Ratnagiri Dhabol JVRatnagiriCCPPII(GTs+STs) Block 3	1,480.00	Long Term	G	5.92
Essar Gas Power Station/ Hazira	330.00	Long Term	P	1.32
Anta Gas Power Station	264.00	Long Term	G	1.06
Auriaya Gas Power Station	448.00	Long Term	G	1.79
Dadri Gas Power Station	524.00	Long Term	G	2.10
Anta Gas Power Station	149.00	Long Term	G	0.60
Uran Gas Station	432.00	Long Term	G	1.73
Essar Gas Power Station/ Hazira	185.00	Long Term	P	0.74
Vadodra Gas Power Station I	145.00	Long Term	G	0.58
vadodra Gas Power Station II	160.00	Long Term	G	0.64
Dhuvaran Gas Power Station	219.00	Long Term	G	0.88
Adamtilla Thermal Power Station	9.00	Long Term	P	0.04
Utran Gas Power Station	99.00	Long Term	G	0.40
Utran Gas Power Station	45.00	Long Term	G	0.18
Gandhar Gas Power Station	393.00	Long Term	G	1.57
Gandhar Gas Power Station	255.00	Long Term	G	1.02
Kawas Gas Power Station	424.00	Long Term	G	1.70
Kawas Gas Power Station	220.00	Long Term	G	0.88
Goa Power Station	48.00	Long Term	P	0.19
Uran Gas Station	240.00	Long Term	G	0.96
Power Station Trombay Gas	240.00	Long Term	P	0.96
Agartala Gas Turbine Power Plant	84.00	Long Term	G	0.34
Kayamkulam Gas Power Station	230.60	Long Term	G	0.92
Pillaiperumalanallur Gas Power Station	225.00	Long Term	P	0.90
Peddapuram Gas power station	220.00	Long Term	P	0.88
Vatva Gas Power Station	66.00	Long Term	P	0.26
Vatva Gas Power Station	34.00	Long Term	P	0.14
Ramgarh Gas Power Station	37.50	Long Term	G	0.15
Uran Gas Station	180.00	Long Term	G	0.72
Pampor Gas Power Station	175.00	Long Term	G	0.70
Tani Bavi Gas Power Station	170.00	Merchant	P	0.68
Jegurupadu Gas Power station	455.40	Long Term	P	1.82
Ramgarh Gas Power Station	3.00	Long Term	G	0.01
Kondapalli Gas power station	350.00	Long Term	P	1.40
Cochin Gas Power Station	135.00	Long Term	G	0.54
Ramgarh Gas Power Station	35.50	Long Term	G	0.14
Ramgarh Gas Power Station	37.80	Long Term	G	0.15
IP CCCP	180.00	Long Term	G	0.72
Power Station Trombay Gas	120.00	Long Term	P	0.48
Basin Bridge Gas Power Station	120.00	Medium Term	G	0.48
Kayamkulam Gas Power Station	119.40	Long Term	G	0.48

[6] Long term sales contracts would typically feature gas cost pass through clauses

Companies (Existing)	Installed Capacity (MW)	Nature of Sales Portfolio[6]	Private / Govt.	Gas Requirment (MMSCMD)
Dholpur CCPP (Ph-I) GT 2	110.00	Long Term	G	0.44
Pillaiperumalanallur Gas Power Station	105.00	Long Term	P	0.42
IP CCCP	102.00	Long Term	G	0.41
Pragati Power Project	104.60	Long Term	G	0.42
Pragati Power Project	104.60	Long Term	G	0.42
Dhuvaran Gas Power Station	220.00	Long Term	G	0.88
VALUTHUR EXT	92.00	Long Term	G	0.37
Godavari gas power station	208.00	Long Term	P	0.83
Karuppur CCGT	70.00	Long Term	P	0.28
Banskhandi Thermal Power Station	10.50	Long Term	P	0.04
Kovikalappal Power Station	69.00	Long Term	G	0.28
Vemagiri CCPP	370.00	Long Term	P	1.48
Kuttalam Gas Power Station	63.00	Long Term	P	0.25
Banskhandi Thermal Power Station	5.00	Long Term	P	0.02
Baramura Gas Power Station	10.00	Long Term	G	0.04
Pragati Power Project	121.20	Long Term	G	0.48
Power Station Trombay Gas	60.00	Long Term	P	0.24
Valuthur Gas Power Station	60.00	Long Term	G	0.24
Baramura Gas Power Station	6.50	Long Term	G	0.03
Tani Bavi Gas Power Station	50.00	Merchant	P	0.20
Karuppur CCGT	49.80	Long Term	P	0.20
Salgaocar Gas Power Station	48.00	Long Term	P	0.19
Baramura Gas Power Station Extn.	21.00	Long Term	G	0.08
Cochin Gas Power Station	39.00	Long Term	G	0.16
Kovikalappal Power Station	38.00	Long Term	G	0.15
Valantharvi GTPP	38.00	Long Term	P	0.15
Dholpur CCPP (Ph-I) ST	110.00	Long Term	G	0.44
Dholpur CCPP U 3	110.00	Long Term	G	0.44
Kuttalam Gas Power Station	37.00	Long Term	P	0.15
RVK	16.00	Captive	P	0.06
Valuthur Gas Power Station	34.00	Long Term	G	0.14
Karaikal Gas Power Station	22.90	Long Term	G	0.09
Valantharvi GTPP	14.80	Long Term	P	0.06
Narimanam Gas Power	10.00	Long Term	G	0.04
Karaikal Gas Power Station	9.97	Long Term	G	0.04
Galoki (Mobile gas TG)	9.00	Long Term	G	0.04
Faridabad CCCGT	286.00	Long Term	G	1.14
Kathalguri Assam Gas Based Power Project	291.00	Long Term	G	1.16
Lakwa Gas Power Station	60.00	Long Term	G	0.24
Lakwa Gas Power Station	60.00	Long Term	G	0.24
Hazira Gas Power Station	104.00	Long Term	G	0.42
Hazira Gas Power Station	52.10	Long Term	G	0.21
Faridabad CCGT	144.00	Long Term	G	0.58
Paguthan Gas Power Station - GT	405.00	Long Term	P	1.62
Namrup Gas Power Station	73.00	Long Term	G	0.29
Rokhia Gas Power Station	48.00	Long Term	G	0.19
Rokhia Gas Power Station	21.00	Long Term	G	0.08
Rokhia GT Extn.	21.00	Long Term	G	0.08
Paguthan Gas Power Station - ST	250.00	Long Term	P	1.00

Companies (Existing)	Installed Capacity (MW)	Nature of Sales Portfolio[6]	Private / Govt.	Gas Requirment (MMSCMD)
Wasteheat Gas Power Station (Namrup)	22.00	Long Term	G	0.09
Konaseema CCPP ST	445.00	Long Term	P	1.78
Kondapalli Power expansion project	366.00	Merchant	P	1.46
Gautami CCPP	464.00	Long Term	P	1.86
Sugen CCPP Blk 1	1,147.50	Part Merchant	P	4.59
Valuthur Ext (ST)	32.40	Long Term	G	0.13
Vijeswaran CCPP	272.00	CPP	G	1.09
Total Existing gas based Power capacity	**16,604.07**			66.42

Name of Power Plant (Proposed)[7]	Private / Govt.	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Kawas II	G					1300	
Gandhar II	G					1300	
Kaymkulam Expansion	G						1950
Tripura gas ILFS/ Pallantana	G			726			
Tripura gas power project	G						100
Shahapur-REL (gas)	P				2800		
Uran Gas Turbine Expansion Plan	S			1220			
Pipavav CCGT	S		702				
Dahej Power Plant	P			400			
Dhuvaran CCPP Extn. Stage III	S			395			
GSEG Hazira Ext	S		351				
Pragati III (Bawana)	S		1500				
Bamnauli Power plant (combined cycle)	P		750				
Rithala combined cycle	P		108				
Gas Based Power Station at Karimnagar	S				2100		
Bidadi combined cycle plant	S						1400
Lakwa WH	S		37.2				
ESSAR Hazira	P		1500				
Utran Stage II/CCPP	S		374				
Total gas based capacity (MW)		16604.07	5322.2	2741	4900	2600	3450
Cumulative capacity (MW)		16604.07	21926.27	24667.27	29567.27	32167.27	35617.27
Total Gas requirment Identified projects (MMSCMD)		66.42	87.71	98.67	118.27	128.67	142.47

Source: Mercados Research

[7] New projects in the private sector would typically feature part merchant capacity.

ANNEXURE - FERTILIZER PLANTS

Gas Based fertilizer plants	Demand	Private/Govt. /Corporation
On HBJ Pipeline	MMSCMD	
National Fertilizers Limited-Vijaipur I & II	3.70	G
Chambal Fertilizers and Chemicals Limited-Gadepan - I & II	4.10	P
IFFCO-Aonla - I & II	4.38	Cop.
IFFCO-Phulpur I & II	3.62	Cop.
KSFL-Shahjajanpur	2.12	JV
Tata Chemicals Limited-Babrala	2.24	P
Indo Gulf Fertilizers Limited - Jagadishpur	2.17	P
SFC-Kota	0.62	P
Non-HBJ Pipeline		
Brahmaputra Valley Fertilizer Corporation Limited-Namrup - II & III	1.95	G
Kribhco-Hazira	3.92	Cop.
Nagarjuna Fertilizers and Chemicals Limited-Kakinada- I & II	3.06	P
Rashtriya Chemicals and Fertilizers - Trombay - V	1.95	G
Rashtriya Chemicals and Fertlizers-Thal	4.30	G
IFFCO-Kalol	1.30	Cop.
GSFC-Vaddora	1.99	G
GNFC-baruch	0.93	
Deepak Fertilizers	0.60	P

New plants/ Switchover demands (MMSCMD)	2009-10	2010-11	2011-12
Naptha Based Plants			
ZIL Goa		1.5	
MCFL Manglore		1.00	
SPIC Tuticorin			1.6
MFL Chennai			1.34
FACT- Udyogamandal			0.91
FO/LSHS Based plants			
NFL-Nangal		1.26	
NFL-Panipat		1.35	
NFL-Bhatinda		1.35	

Closed Units (MMSCMD)	2009-10	2010-11	2011-12	2012-13
FCI-Sindri				2.12
FCI-Gorakhpur				2.12
FCI-Ramagundam			2.12	
FCI- Talcher			2.12	
HFCL-Barauni				2.12
HFCL-Durgapur				2.12
HFCL-Haldia				2.12

Source: Mercados Research