SAARC ENERGY CENTRE

Feasibility Study for Setting up SAARC Regional/Sub-regional LNG Terminals

- *Haseeb Sherer*

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Abbreviations

bbl	:	barrel
bcm	:	billion cubic meters
cbm	:	coal bed methane
CGD	:	city gas distribution
cm	:	cubic meters
CNG	:	compressed natural gas
DES	:	delivered ex-ship
DFDE	:	dual fuel diesel electric
FOB	:	freight on-board
HH	:	Henry Hub
I&C	:	industrial & commercial
IP	:	Iran Pakistan
IPI	:	Iran Pakistan India
IUK	:	interconnector UK
JCC	:	Japan customs cleared
kms	:	kilometers
m^3	:	cubic meters
mcm	:	thousand cubic meters
MENA	:	Middle East North Africa
mmBtu	:	million British thermal units
mmcm	:	million cubic meters
MT	:	million tonnes
MTOE	:	million tonnes of oil equivalent
MTPA	:	million tonnes per annum
NBP	:	national balancing point
NGV	:	natural gas vehicles
OTC	:	over the counter
r/p	:	reserves to production ratio
scmd	:	standard cubic meters daily
TAPI	:	Turkmenistan Afghanistan Pakistan India
tcf	:	trillion cubic feet
tcm	:	trillion cubic meters
TOE	:	tonnes of oil equivalent
WTI	:	West Texas Intermediate

Forward

This desktop study conducted by the SAARC Energy Centre (SEC) under a contract to look at the current status of natural gas and LNG industries in the SAARC member countries, with a view to identify potential areas of mutual cooperation including setting up regional / sub-regional LNG import terminals. While the material has been be reviewed by outside experts before release, the views and opinion expressed in the report are those of the original author and do not necessarily represent the position or views of the SAARC Energy Centre. The report is meant to facilitate discussion and identify specific cooperation areas for promotion of regional energy cooperation especially in the new and fast growing area of LNG imports.

Natural gas has remained the fuel of choice in parts of South Asia where it was domestically available including Bangladesh, India and Pakistan. As the mainstay of the energy supply mix in Bangladesh and Pakistan and as the preferred fuel in India now, the domestic supply has faced a daunting task of matching a runaway demand. The supply demand gap grew to such an extent that the imports were or are being introduced into the mix. A number of pipeline import options have been considered and some are likely to be completed in the future, but the near term shortage has been largely met via LNG imports, especially in India.

The arrival of LNG marks the start of a new phase of local and regional gas market development. The two salient features of the domestic gas which underpinned its development, abundance and cheap, have been compromised as dwindling local gas is supplemented with international LNG cargoes at volatile oil linked prices. While this creates a whole new set of challenges previously unheard of in the context of gas consumption, the timing coincides with substantial growth in international LNG trade which is seeing more and more buyers and sellers joining in to confirm LNG being established as an internationally traded fuel. Continuing growth in inter-regional trade and maturing markets will eventually allow price harmonisation across different markets with enhanced liquidity and transparency.

The growth of LNG's share in the energy supply mix also highlights the urgent need to introduce the next level of enhanced sophistication in energy policy and regulation. These reforms should reiterate and further promote competition and price transparency as well as ensure non-discriminatory access to infrastructure for efficient allocation of resources and lowering the cost to consumers. Regulatory certainty and accommodative policies can go a long way towards encouraging the private sector to participate and even lead in making large investments needed to modernise or augment energy supply capabilities in these rapidly developing countries.

SAARC member countries can also promote cooperation between themselves as each country embarks on its import driven gas market development. Apart from sharing commercial and technical experiences, these neighbouring countries can also look at setting up joint facilities for cost sharing and optimum utilisation. The study explored the possibility of setting up joint LNG terminals for the benefit of all but found that while such a project will be commercially attractive, it may not offer any cost advantage to dedicated terminals located in each country as the region's gas grid is not interconnected. So in order for the gas to reach another country, the interconnect cost via new pipeline as well as haulage across the host network will make it a costly proposition.

Mr. Mohammad Naeem Malik
Director, SEC

Acknowledgment

I would like to thank the staff and the management at SAARC Energy Centre (SEC) for the considerable help and support they provided during the preparation and finalisation of this report. The availability of regional data and country reports in a uniform format was indeed a great help. Completion of this study while based in Australia meant having to cope with time difference, sometimes as much as 6 hours, so the exceptional flexibility and cooperation shown by Mr. Ahsan Javed and others helped finish this report well within time stipulated.

Thanks to Mr. Mehboob Elahi who provided useful comments and feedback during the finalisation of the report and its dissemination during this important and timely workshop which was well organised by SEC, including Mr Mohibur Rahman. Finally thanks to my wife Nayyer for having to bear nightly skype calls to discuss the report during its formulation and my bad habit of reading out loud while typing.

Mr. Haseeb Sherer
Author

Executive Summary

This report was prepared on behalf of the SAARC Energy Centre (SEC) under a project to determine the scope and viability of promoting regional cooperation in LNG within South Asia. The work was a follow up to the recommendations proposed during the first meeting of the SEC's Expert Group on Oil & Gas and the SAARC Regional Energy Trade Study (SRETS), both highlighting the need for exploring avenues for regional energy cooperation with special emphasis on LNG, being the new and upcoming imported fuel being introduced by some member countries into their energy supply mix. In accordance with the Terms of Reference prepared by SEC and approved by its Board, the Study therefore forms the first step into looking at the potential and scope of cooperation that can be promoted within SAARC member countries and to formulate recommendations for further work in this area.

Feasibility Study for Setting up SAARC Regional/Sub-regional LNG Terminals was prepared over a 3 month period during the third quarter of 2015 using data and material publically available. Fortunately useful work was readily available in terms of SEC's periodic compilation of energy supply and demand statistics for the SAARC member countries. This was supplemented with BP's annual statistical review to help visualise regional situation in a global context. Ideally a more timely and recent data beyond the SAARC Energy Data book 2011 would have been helpful but the trends observed in terms of heavy domestic reliance on indigenous energy resources and the corresponding energy mix in each country should still be consistent and valid.

The report can broadly be classified under four sections. The first covers the current energy supply mix of member countries, both individually as well as collectively. It identifies the special role that natural gas plays in three member countries - Bangladesh, India and Pakistan. A transition from the dominant domestic fuel in each of these countries, to now being topped up via imports (currently LNG), is more or less similar for all of them. The second section takes a quick look at the International LNG scene to familiarise the readers to global trends in LNG and the factors / drivers influencing its direction and focus. With the international trade in natural gas rapidly being dominated by new LNG exporters as well as importers, it looks at the factors helping its wider appeal such as use of unconventional gas as feedstock and development of modular / floating technologies etc. A look at the evolution of markets / hubs and how it has shaped a more efficient way to price LNG is discussed along with the long term oil linked prices that underwrote many projects.

The third section takes a look at the local gas scene in each country and how the domestic policies and priorities are shaping up the energy sector, especially natural gas and its supply and demand. The various gas import projects embarked upon, their current status and major issues and challenges being faced. Based on the common theme that develops after studying individual gas sectors, the study proposes certain structural reforms that can assist promoting efficiency and transparency in each country. It also looks at how collectively the countries can help each other by sharing know how and reduce transactional costs by moving to a regional approach as opposed to a national one.

The last section is devoted to looking at the prescribed areas of cooperation such as setting up the regional LNG terminal(s) and their indicative costs / benefits to see if it will be feasible to then define the next steps. The feasibility then looks at the likely costs of power generation based on RLNG from regional terminal as well as comparison of RLNG on individual as well as regional basis. Using these indicative figures, it proposes the next steps that member countries can take to enhance cooperation in this area.

Interestingly and as observed during preparation of this report, the ongoing transition by SAARC gas consuming countries from heavy reliance on domestic energy resources to an increasingly import driven energy mix is happening exactly when the international energy prices are also undergoing a major re-alignment. The dominance of shale gas in the US and now CSM based LNG projects in Australia have suddenly extended the reach and affordability of LNG. The abnormally low spot prices of LNG is definitely a big help for the SAARC member countries as they absorb the financial impact of transitioning to imported gas which was traditionally sourced and priced locally. The reduced burden, however, should not downgrade the need to introduce transparency and efficiency in the energy sector, both at national and regional level. SAARC member countries can share individual experience and learning for the collective good of their region and help promote energy security for a better tomorrow.

CHAPTER 01

1.1 Introduction

The South Asian region is a diverse group of fast growing developing countries, characterised by their varying size and demographics as well as the different combination of energy mix deployed to satisfy their ever growing energy needs. Population increase combined with urbanisation and the need to diversify their economies has resulted in an enormous challenge for these countries to meet their energy demand. As net importers of energy, the region has been striving to utilise indigenous energy resources to augment and / or replace biomass which still dominates the rural landscape in these countries.

A quick look at their energy profile and how it has evolved over a 10 year period between 2001 and 2011, as compared to the world average[1], helps us understand the dynamics at work in this region.

Primary Energy Consumption MTOE, 2001 vs 2011

	SAARC		WORLD	
	2001	**2011**	**2001**	**2011**
Oil	133.2	186.9 *+40%*	3,609.8	4,085.4 *+13%*
Natural Gas	48.7	95.0 *+95%*	2,221.0	2,943.8 *+33%*
Coal	252.0	382.7 *+52%*	2,406.3	3,777.4 *+57%*
Hydro electric	20.6	36.9 *+79%*	586.7	795.5 *+36%*
Others	107.8	211.6 *+96%*	655.2	805.2 *+23%*
	562.3	913.1 *+62%*	9,479.0	12,407.3 *+31%*

Source: SAARC Energy Data Book, 2001 – 2011, BP Review 2015

The overall increase in energy consumption in the SAARC region was twice as fast as the world average[2] during the 10 year sample period between 2001 and 2011, highlighting the significance of economic growth and its impact on their appetite for energy consumption. The rate of growth of individual energy sources, however, demonstrates a varying trend.

The continued reliance on biomass by their mainly rural population continued at a rate which was almost three times as fast as the world average. Meanwhile, growth in coal consumption stayed very much in line with the world average. Both Hydroelectricity and oil consumption grew at twice the global average but it can be argued that their growth may to some extent have been constrained by a large import bill in the case of oil burdening the national finances and limited new sites / projects and other social issues with building new Hydro capacity. The clear standout has been natural gas which, as an indigenous energy resource (where available), has

[1] SAARC data comprising India, Pakistan and Bangladesh using SAARC Energy Data book
[2] BP Statistical Review of World Energy, 2015

done some serious heavy lifting in terms of offering a clean and reliable fuel of choice in industry, households and more recently, in transport too.

Natural Gas is unique in the way it is developed and utilised. Unlike oil which is a global fuel and has a ready international market, gas has to have a dedicated supply chain, linking (usually) domestic gas reserves with local demand centres via necessary pipeline infrastructure. Rapid gas development in the SAARC region in the last decade or so highlights the serious effort and commitment shown by relevant countries of the region to bolster their indigenous energy resources. Unfortunately, as gas reserves are not evenly distributed, only three of the total eight SAARC member countries which have been endowed with gas reserves namely, Pakistan India and Bangladesh, accounted for all this usage and the ensuing growth.

CHAPTER 02

2.1 Gas in the SAARC Region

Like their colleagues in the SAARC region, Bangladesh, India and Pakistan are reliant on abundant new energy supplies to feed their economic growth and facilitate the ongoing urbanisation programmes. Indigenous gas supplies not only help them diversify their energy mix but also help with security of supply and an invaluable offset against the burgeoning costs of energy imports. The development of the gas industries in these countries is a useful example for other oil importing developing countries in how diversification and increased reliance on domestic resources can help sustain rapid growth.

Use of gas started quite early in Pakistan with the discovery of the giant Sui gas field. Flexible approach and a strong government desire to maximise the use of this abundant domestic energy resource meant rapid growth in consumption with all sectors of the economy benefitting, especially domestic consumers as Pakistan became one of the very few developing countries with an extensive network of gas transmission and distribution system traversing across the country allowing even far flung regions to enjoy the benefits of the clean and domestically available fuel.

Bangladesh saw its first hydrocarbon discovery around mid-1950s with Sylhet coming into production in 1960. Since then, gas has made rapid strides in not only having established as a fast growing domestic energy resource with active private sector participation but its demand and contribution to local economy has multiplied many times over.

India has traditionally relied on domestic coal which is abundantly available locally. While gas use has been around for some time, the focus got a renewed impetus in mid-1990s with government's desire to encourage domestic gas use to supplement oil and coal which account for almost two thirds of India's energy demand. The country's oldest offshore gas field, Bombay High, has been a very productive resource, supplemented by the Krishna-Godavari Basin in recent times. This resulted in phenomenal growth in gas sector including associated infrastructure and downstream industries.

The early utilisation efforts concentrated on setting up limited pipeline infrastructure and bulk industrial use. Since then, gas has come a long way in being a significant contributor to their energy mix as shown in the table below: -

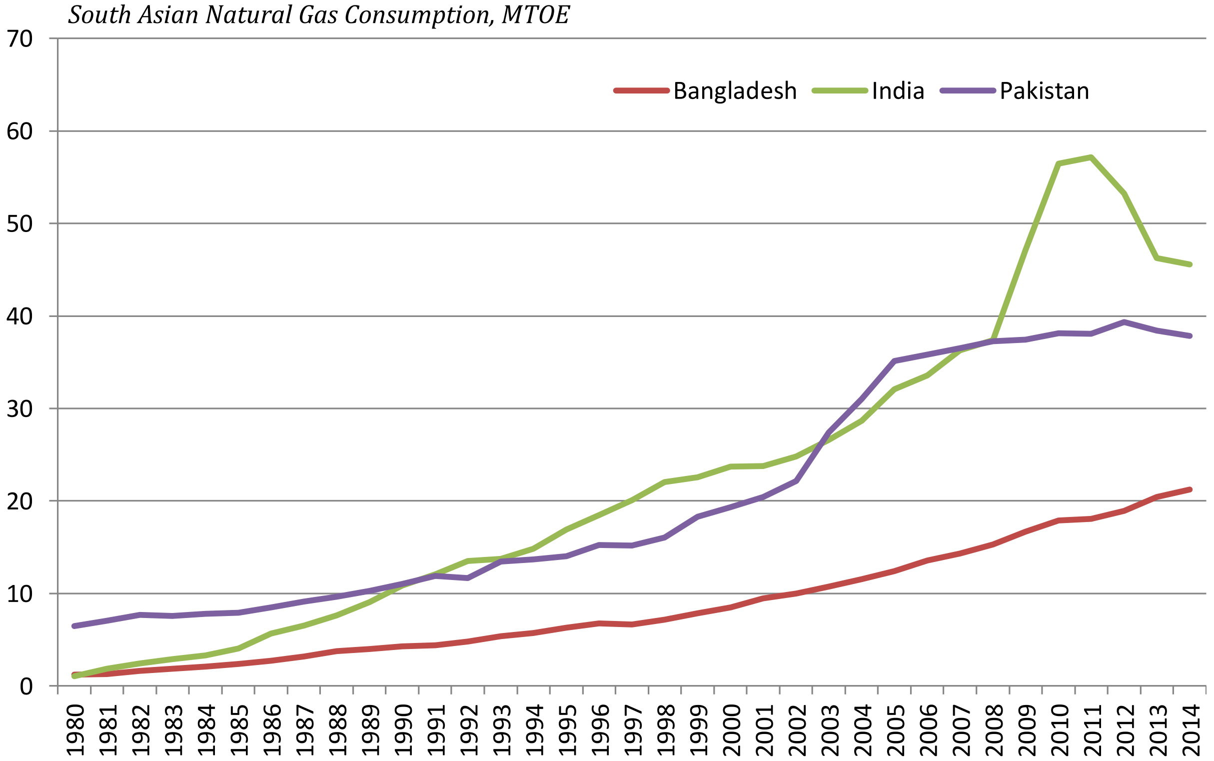
Commercial Energy Consumption MTOE, 2013 vs 2014

Sector	Bangladesh	India	Pakistan		Bangladesh	India	Pakistan	+ / -
Oil	5.3	175.3	21.8		5.7 *8%*	180.7 *3%*	22.6 *4%*	*3%*
Natural Gas	20.4	46.3	38.4		21.2 *4%*	45.6 *-2%*	37.8 *-2%*	*0%*
Coal	1.0	324.3	3.5		1.0 *6%*	360.2 *11%*	4.9 *37%*	*11 %*
Nuclear	-	7.5	1.2		-	7.8 *4%*	1.1 *-5%*	*3%*
Hydro / Renewables	0.2	42.3	7.0		0.2 *0%*	43.5 *3%*	7.2 *3%*	*3%*
Total	26.9	595.7	71.9		28.2 *5%*	637.8 *7%*	73.6 *2%*	*7%*

Source: BP Statistical Review of World Energy, June 2015

Gas offers a significant contribution to each country's energy mix and while demand for other fuels has also increased, the share of gas has seen an unprecedented growth as the chart below illustrates: -

South Asian Natural Gas Consumption, MTOE



Source: BP Statistical Review of World Energy, June 2015

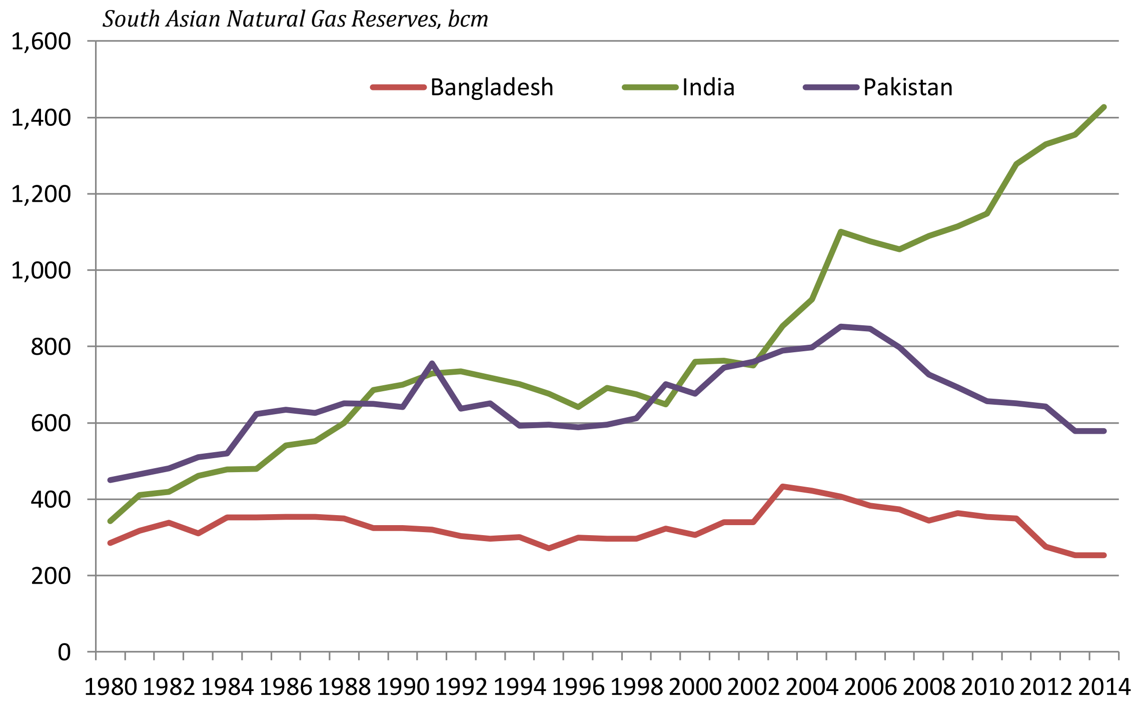
From its humble beginning in early / mid-sixties, gas now accounts for more than two-third of primary commercial energy mix of Bangladesh and more than half in the case of Pakistan.

Although Gas's share in India is relatively modest at around 8% of its energy mix, its rapid growth on the back of fast growing LNG imports highlights its significance to the economy.

Growth in gas consumption has consistently surpassed economic growth in South Asia, largely driven by the desire to substitute imported oil in the case of Bangladesh and Pakistan while India has been encouraging gas use to diversify its energy sources and supply security. Gas therefore not only found its way into the traditional markets such as domestic, commercial and Industrial as well as fertilizer manufacturing but saw a significant surge in its use as CNG in the transport sector. It is due to this phenomenal growth that the recent consumption pattern has started to taper off, especially in India and Pakistan as traditional supply sources are struggling to cope with the demand as illustrated in the graph.

Proven gas reserves at the end of 2014 in Bangladesh stood at 300 bcm in Bangladesh, 1400 bcm in India and about 600 bcm in Pakistan. This gives the Reserves to Production (r/p) ratio or reserves life at current production rates of 11 years for Bangladesh, 45 years for India and about 14 years in the case of Pakistan. The very low rates for both Bangladesh and Pakistan explain why recent trends of constraining its use have come into play.

While early signs were very encouraging, gas reserves in Pakistan have failed to keep pace with rapidly rising demand. One view has been that the level of incentives for exploration and downstream price controls has failed to attract enough activity in upstream exploration investments. The exploration terms have definitely been looked at in recent times and the terms have improved.



Source: BP Statistical Review of World Energy, June 2015

The Government has however maintained its role of determining sectoral gas prices with a clear focus on keeping gas accessible for residential and commercial users. In terms of priority allocation too under constrained supplies, households get the first preference followed by Power, Fertilizer Cement and finally CNG. Load shedding of gas is however rampant and the situation worsens in winter when daily swings in seasonal space heating load add to the growing supply / demand gap. Some estimates put this growing annual gap at more than 15 bcm and is bound to grow with continuing population and economic growth.

Bangladesh is facing the same supply gap as Pakistan and is evident in broad electricity load shedding that exists due to lack of gas availability to fully utilise the available generation capacity[3]. Overall gas consumption has increased more than 4 times within 20 years with power generation accounting for some 60% of the total gas take. Of the total 23 bcm/a currently produced, roughly 10 bcm/a is produced by the domestic Petro Bangla and the remaining 13 bcm/a are supplied by Independent Oil Companies. The Government has been keen to maintain gas production at current rates but the existing fields which are already producing at the maximum rates, need an extensive programme of E&P activities to even maintain the current rates. The estimated supply gap has already grown to more than 8 bcm/a and has forced the Government to encourage oil based small to mid-sized power units on rental basis to alleviate the gas shortfall for power generation.

India's steep jump in gas use started with the discovery and rapid development of the Krishna Godavari (KG) basin which prompted investments in gas transmission as well as downstream utilisation. Together with the original producing field, Bombay High, the two account for almost all the offshore gas production in the country. Gas fired power generation constitute roughly half of domestic consumption, the rest taken up by fertiliser (23%), petrochemical industry (14%) and the residential and commercial (13%). As the older field matured, the expectation was for KG to not only take up the slack but also grow in line with the gas demand growth. Production rates have however come down unexpectedly and may require considerable effort to restore / maintain the production profile. With price controls on gas sales, the gas demand has far outstripped supply and required immediate steps to launch LNG imports to fill the void. The gas demand is expected to continue to grow by more than 4% for the next 20 years. Some attempts have been made at unlocking the unconventional gas resources such as coal bed methane but despite having sizeable coal bed methane (cbm) resources, the contribution so far has been negligible.

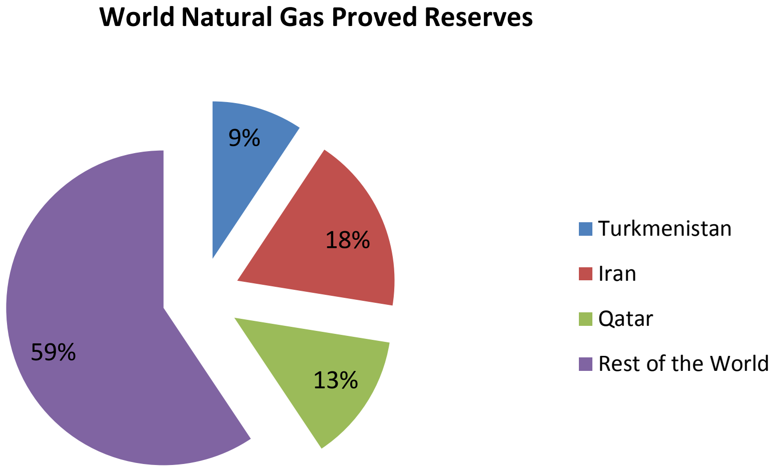
To summarise, gas has long been the fuel of choice in countries of South Asia which are endowed with it. Early start with favourable environment and modest expectations on behalf of producers allowed domestic gas to quickly grow and occupy a dominant role in the countries' energy mix. These gas producing countries have thus been able to substitute imported oil with gas as a cheap and abundant local fuel. Customer price controls, while encouraging large gas utilisation, have limited the incentives for upstream investments in exploration and / or pipeline infrastructure, causing widespread supply shortfall overtime as the existing supplies and facilities are maxed out. Governments are now actively involved in finding solutions to this by looking at means to minimise gas curtailment via fuel substitution, where possible, and looking at gas import via pipelines as well as LNG.

[3] Research Report: Energy Sector of Bangladesh 2011

2.2 South Asian Gas Imports – Current Status

South Asia is fortunate to be located very close to some of the largest gas resources in the world. It is no surprise, therefore, that even before the gap started to emerge between domestic gas supply and the fast growing demand, the idea that gas can be brought in from a neighbouring country was already being explored.

Regional countries in the Middle East and Central Asia bordering South Asia can be classified as gas giants with total reserves in excess of 76 tcm or more than 41% of the global proven gas reserves.



Source: BP Statistical Review of World Energy, June 2015

A number of schemes have been looked at, some very ambitious such as an undersea pipeline from Qatar to Pakistan in early 90s. The Iran to Pakistan (IP) pipeline was perhaps the first one to go beyond the conceptual stage and was launched in 1995, with initial plans to connect gas producing region of Southern Iran to natural gas markets in Pakistan as well as extend it all the way to India. The project has seen many challenges right from its inception with difficult negotiations and controversies on issues such as pipeline route, security concerns, tariffs/transit fees and financing to name a few. Political pressure and economic sanctions applied on Iran resulted in India ending its participation and while Iranians have completed their section of the pipe, Pakistan is yet to build its side of the 1,600 kms pipe citing both funding shortfall as well as the threat of sanctions so far. With the nuclear deal with Iran now done, the project has regained its focus with Pakistan counting on Chinese help to build some 700 kms of pipeline within its territory to allow imported Iranian gas to feed into its transmission grid. There are signs that the project will finally be underway with imported gas largely feeding into local power generation.

The Turkmenistan to Afghanistan, Pakistan and India (TAPI) is another pipeline project that has failed to materialise even after a long time due to a combination of geopolitical, technical and financial challenges but most importantly due to war and instability in Afghanistan. The 1,800 kms pipeline is expected to supply 33 bcm/a when completed at a cost of more than $ 10 billion. Led by TurkmenGaz of Turkmenistan, the project consortium has ADB's financial backing but will still need supplemental funding to complete the project. There have been some recent developments such as a renewed commitment by the project proponents with a target start for Dec '15 and completion by 2018 but these deadlines seem ambitious. Recent media reports indicate the project has been launched by Turkmen government by ordering state owned TurkmenGaz to start construction of pipeline at their end[4]. It can be hoped that this renewed commitment should encourage international participation with technical help and financing.

The Myanmar-Bangladesh-India (MBI) pipeline is another un-finished scheme to tap into regional gas resources by setting up an interstate gas supply chain. The project was discussed in mid-2000s between three countries, Myanmar with producing fields (some involving Indian oil companies), Bangladesh as the transit country and India as the destination country with the gas demand. Protracted negotiations due to difficulty in aligning expectations and priorities failed to allow any material progress. Meanwhile, Myanmar negotiated another pipeline project with China to effectively supply gas from the same fields that were to feed into the Bangladesh / India pipeline. With the Chinese project already completed, any chance of reviving the original project has now become marginal at best.

With all the pipeline gas import options yet to take any shape, the idea to introduce LNG into the energy mix was first adopted by India with a long term deal to buy Qatari Gas from 2004. Since then, India has established itself as a fast growing LNG importing nation with a number of LNG receiving and regasification terminals along its west coast with significant expansion planned in line with increased LNG use.

The share of Imported LNG constitutes almost a third of the gas consumed in India, bought under a number of long and short term contracts. The original contract with Qatargas from their new LNG export facility back in 2004 for 7.5 MTPA was supplemented with another long term contract for 1.44 MTPA with Mobil Australia from Gorgon in Western Australia and with Chenniere Energy for an additional 3.5 MTPA from its Sabine Pass facility in Louisiana USA.

The two original LNG import terminals in Gujarat, Dahej (10 MTPA) and Hazira (3.5 MTPA) have been in operation since 2004 while the new Dhabol (5 MTPA) terminal commenced in 2013. There is an ambitious programme to not only augment the capacity of the existing plants as well as add new facilities to match increasing LNG use. It is estimated that the current total capacity of 17 MTPA will increase three fold in the next 10 years with a potential addition of 5 new terminals.

Asian LNG scene has long been dominated by Japan and Korea. With a very heavy reliance on imported energy, the large power and gas utilities in these countries have collectively been the largest buyers of LNG in the world. Because of their thirst for energy and in the absence of any pricing benchmarks, LNG prices to these markets have tracked oil prices and therefore sold at a premium compared to European prices. While there is now a serious push to de-link East Asian LNG prices with oil with some progress, Indian LNG contracts also carry some sort of oil price indexation. This makes it very challenging to make an economic case for wider LNG use when downstream prices are controlled yet upstream LNG prices are exposed to international oil price volatility.

Recent softening of both crude oil as well spot LNG prices have created an incentive for Indian buyers to rely on spot / short term LNG cargoes at the expense of the less flexible long term contracts with relatively higher prices. There is also some talk of a possible renegotiation of

[4] http://www.isgs.pk/projects/turkmenistan-afghanistan-pakistan-india-gas-pipeline-tapi-4

these long term contracts by way of a price review to bring the contract prices more in line with the current spot prices.

Pakistan's involvement with LNG has proven to be as challenging as the pipeline import options. Facing serious bottlenecks / issues with TAPI / IPI projects for gas imports and a lack of any major headway to fill this void, the Government showed its intent in 2005 to pursue LNG imports by first inviting tenders for the construction of an LNG import and gasification terminal at Port Qasim in Karachi. With lack of any serious progress on this, the tender was subsequently revised to include both the construction of the terminal as well as supply of LNG. Although bids were shortlisted, the project could not proceed as the deal was challenged in the Supreme Court which halted signing / award of the relevant contract.

There is a long chronology of follow up tender calls, media announcements and political statements to show that efforts continued to be made to finalise a deal with Qatar and for setting up the regasification terminal which finally resulted in Pakistan receiving its first LNG cargo in March 2015. Since then the Floating Storage & Regasification Unit (FSRU), Exquisite and / or Excelerate have made a number of trips to Qatar to bring back LNG for offloading at Port Qasim. Pakistan State Oil has recently invited tenders for supply of 4 cargoes of 143,000 cm LNG between July and October 2015. The majority of the gas is expected to be used for power generation by displacing fuel oil although the Government has offered some tax relief for other sectors to cushion some of the price jump of imported LNG against the much cheaper domestic gas.

Bangladesh in 2010 highlighted a plan to augment its gas supplies via LNG imports. An import terminal at Moheshkhali Island, near Cox's Bazar, with a capacity of 5 bcm/a was targeted along with associated berthing facilities to accommodate LNG ships. Separately, the Government pursued negotiations to purchase LNG from Qatar. While interest has been shown by various parties, no deal has been finalised yet due to issues with financing, credit risk and lack of requisite infrastructure etc. More recently, an integrated LNG based power project has been proposed by Reliance Power of India whereby the import terminal at Moheshkhali will be built to supply regasified LNG to a 3000 MW power plant in Bangladesh.

To summarise, all the three South Asian countries with natural gas markets have been actively seeking pragmatic supply side solutions to augment domestic gas production. Relative proximity to some of the world's largest gas deposits meant a number of interstate pipeline projects have been considered to meet a fast growing domestic demand. While geopolitical considerations and regional security have played a major part in impeding a quick and smooth implementation of these projects, other factors such as regulatory development and price controls, multilateral funding and credit risk have also continued to play their part.

As the supply gap kept growing bigger and bigger, these Governments have pursued LNG import options to varying degrees. India has lead the charge here with an active LNG import profile since the mid-2000s. Pakistan too has overcome technical, legal & regulatory hurdles and recently started receiving LNG with procurement tenders out to show this will be an ongoing activity. Similarly, Bangladesh has well developed plans to support its gas fired power generation with imported LNG and a likely launch is getting closer.

There is no doubt that each regional gas market is different with its unique flavour and characteristics but as South Asia evolves into a mature gas market, there are issues that need to be faced and lessons to be learnt from other markets to streamline growth and promote efficiencies in setting up a robust gas supply chain.

CHAPTER 03

3.1 Global Quest for LNG

Since the first commercial scale LNG plant at Arzew in Algeria commenced operation in 1964, the LNG industry has seen a phenomenal growth in its business of offering a truly international fuel of choice by way of its greener environmental credentials and flexibility in sourcing. So while the global natural gas demand has risen by about 2.7%, the LNG demand has risen more than 3 times faster as it catered to the demand of fast growing economies in Asia and offered diversity of supply to established gas markets in Europe.

Although there may be specific reasons why a certain country may want to import LNG, generally the broad reasons for its introduction can be categorised as follows: -

3.2 Supply Boost

In countries where gas is already well established as a fuel, LNG helps to either supplement or even replace the dwindling domestic supplies. These countries have long been major gas producers but with domestic supplies tapering off, they turn to LNG to maintain a supply / demand balance. UK and Netherlands are two such examples in Europe who have long been major gas producers but now regularly receive LNG into their gas markets. In South Asia, both Bangladesh (will) and Pakistan (now) fall under this category.

3.3 Security and Diversity

Often the countries are driven by a desire to diversify their fuel and / or supply sources to avoid a situation where they are too heavily reliant on a certain fuel or a supply region for risk mitigation purpose. By introducing LNG into the mix, they can not only add flexibility with the suppliers but can also allow wider choice of fuel for their industry. A lot of LNG supplied into Europe falls under this category as the participating countries augment or diversify their reliance on pipeline imports.

3.4 Environment

Natural gas is the cleanest of all the fossil fuels. As it is primarily made up of methane, the products of a complete combustion are water vapour and carbon dioxide. Combustion of coal or oil on the other hand, results in higher carbon as well as nitrogen and sulphur emissions. With a far greater emphasis being placed now on decarbonisation of economies, natural gas deficient countries can rely on LNG to enjoy the environmental benefits without having to restrict themselves with geographical considerations. Advancements in technology have allowed LNG carriage to distant locations with great efficiency and flexible volumes. Both China and India can be included here especially China which is now the largest energy consumer in the world and actively trying to minimise emissions by reducing coal use and replacing it with imported LNG.

3.5 Flexibility

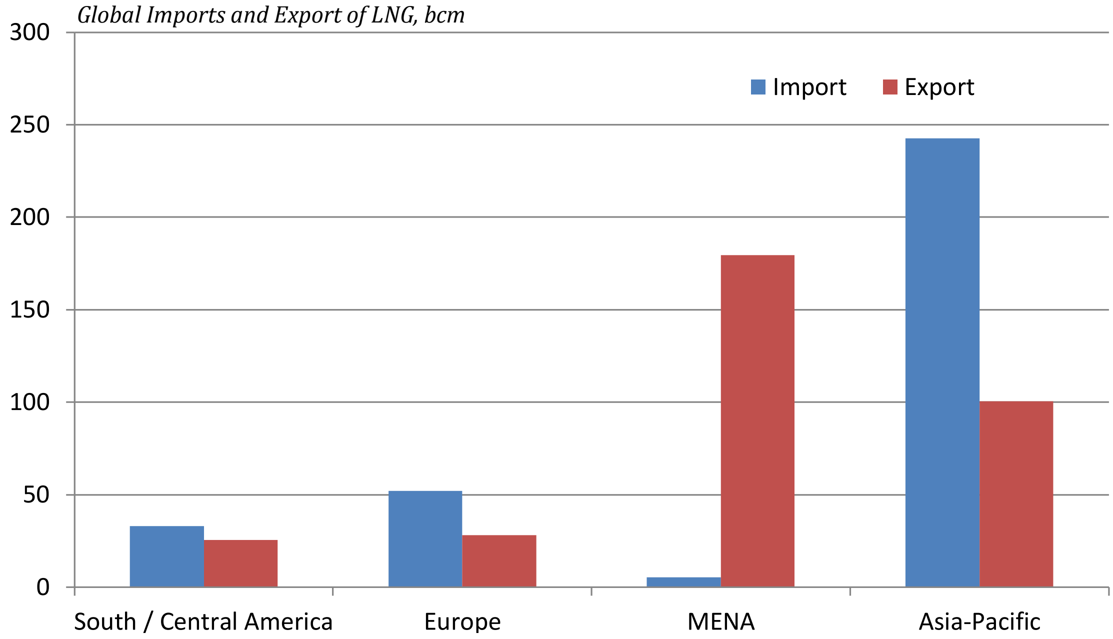
While earlier LNG trade was characterised by long term supply deals with buying countries, LNG trade is increasingly carried out by way of spot or short term arrangements which allow the flexibility for the buyers to manage seasonal or cyclical loads such as spot deliveries in winter to manage peak daily quantities. Many countries in Europe including the UK for example rely on LNG to boost their daily gas send out to match the extra system demand.

CHAPTER 04

4.1 International LNG Market

International trade in natural gas accounts for almost one third of the global gas consumption. Of the annual 997 bcm total traded volume worldwide, LNG is roughly a third while the rest is traded via pipeline imports such as the Russian gas delivered into Europe.

The LNG trade has grown at about 8% annually and stand at a total of 333 bcm at the end of 2014. The Asia-Pacific region has traditionally been the dominant exporter of LNG but has since been joined by Middles East and North Africa (MENA) along with small contributions from Rest of Africa, South America and Europe.



Source: BP Statistical Review of World Energy, June 2015

On the demand side, Asia-Pacific commands almost 73% of the entire LNG imports, followed by Europe at 16% and the balance attributed to North / South America (10%) and MENA (1%). Japan is the largest LNG user in the world with more than a third of the entire LNG consumed followed by South Korea. China which started importing in mid-2000s is the fastest growing market with contracts in place from a number of new LNG projects to boost its share.

Both China and India are rapidly increasing LNG's share of their overall energy mix which has traditionally seen a low contribution from natural gas but a very high dependence on domestic coal which is abundant in both countries. Much of the recent tilt towards LNG can therefore be attributed to the desire to check environmental degradation and improve urban air quality.

In terms of sectoral use of imported LNG, the gas consumption is concentrated in the power sector which makes up about 40% of its overall use. Industrial demand then accounts for the second largest share at 23% which is not too far behind residential sector.

Variations however exist between regions. Asia Pacific dominated by Japan and Korea see a dominant role for LNG in power generation. In Europe, residential and commercial sectors are the major users due to high natural gas penetration rates in the domestic market. Gas use in the

Industry is also quite varied with countries having heavy industries see a larger share of gas use whereas sophisticated industries with less energy intensive processes see a much smaller role for gas.

Just as the number of countries importing LNG has grown over time, so have the LNG exporting countries. The traditional LNG exporting countries in North Africa and Far East have now been trumped by new supplies from the Middle East, Russia, Australia as well as the growing influence of US and Canada. In 2006, 13 countries were LNG exporters while 15 countries were importers. In 2014 the list of LNG importing countries has grown to 29 while 19 countries are exporting LNG[5].

International LNG Trade in 2014, bcm

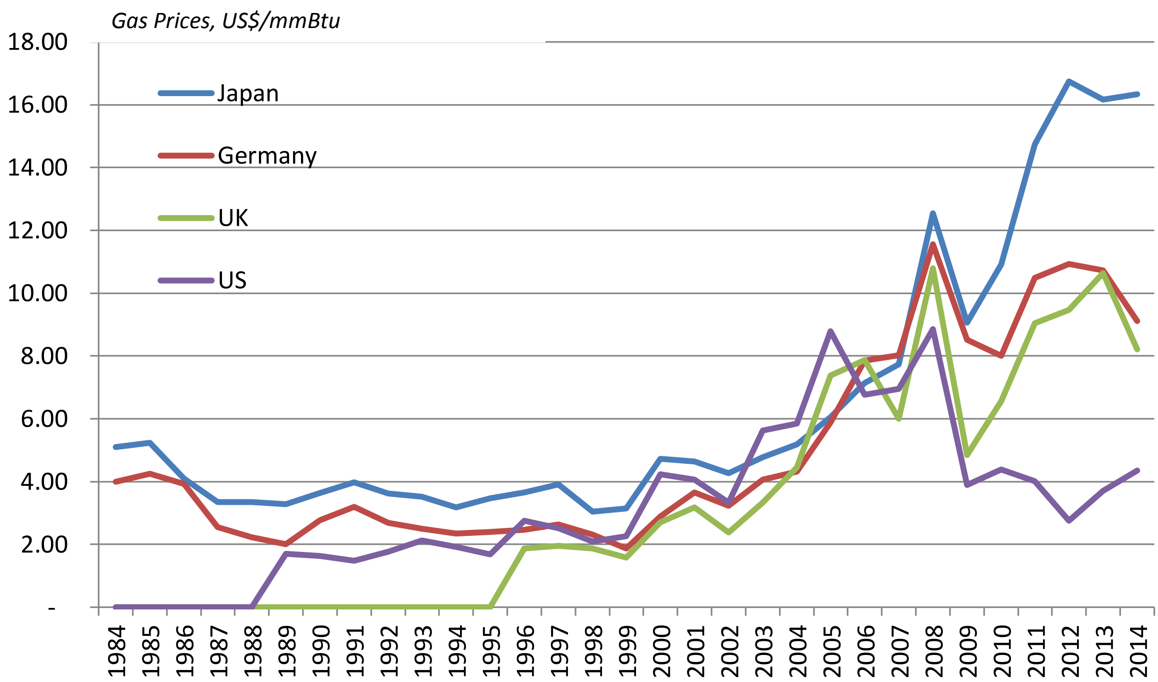
	To	North America	S. & C. America	Europe and Eurasia	Middle East	Asia Pacific	Total exports
From	US*	-	0.1	-	-	0.3	0.4
	Brazil*	-	0.1	-	-	-	0.1
Trinidad &	Tobago	2.2	11.5	3.1	1.2	1.2	19.3
	Peru	4.3	-	1.3	-	0.1	5.7
	Norway	0.3	1.3	2.7	-	0.9	5.3
Other	Europe*	0.3	2.9	0.8	0.4	3.8	8.2
Russian	Federation	-	-	-	-	14.5	14.5
	Oman	-	-	0.2	0.1	10.4	10.6
	Qatar	1.4	1.7	23.6	2.3	74.4	103.4
United	Arab Emirates	-	-	-	-	8.0	8.0
	Yemen	0.2	-	-	0.4	8.3	8.9
	Algeria	-	0.1	14.6	-	2.6	17.3
	Angola	-	0.1	-	-	0.4	0.5
	Egypt	-	-	-	-	0.4	0.4
Equatorial	Guinea	-	0.5	0.1	-	4.4	5.0
	Nigeria	2.5	3.0	5.8	0.7	13.3	25.3
	Australia	-	-	-	0.1	31.6	31.6
	Brunei	-	-	-	-	8.3	8.3
	Indonesia	0.3	-	-	-	21.4	21.7
	Malaysia	-	-	-	0.3	33.7	33.9
Papua	New Guinea	-	-	-	-	4.7	4.7
South	Korea*	-	-	-	-	0.2	0.2
	Total Trade	11.6	21.4	52.1	5.4	242.7	333.3

Source: BP Statistical Review of World Energy, June 2015

[5] World LNG Report - 2015 Edition

The phenomenal rise of LNG as an internationally traded energy commodity can be illustrated by the fact that traded volumes have increased 2.5 times between 1990 and 2014 to 241.1 MT. While Asia Pacific, the traditional source of LNG exports, provided 31% of world LNG the fast growing Qatari capacity build up saw Middle Eastern share of the total LNG supplies increase to 41% with Qatar's own share nudging past 77 MT or about a third of the global LNG supplies. In recent years, Middle East has emerged as a swing producer, supplying both the Atlantic and Pacific markets. The shale gas boom in the US has had a dramatic effect on the international LNG supply scene. A large surplus of domestically available shale gas has meant the US which was looking to import LNG to supplement its gas requirement only a few years back, is now a major new player with a number of LNG export projects at various stages of completion. Moreover, the expansion of the Panama Canal now provides an opportunity for US Gulf Coast LNG to be sold to users in the Pacific region with lower Henry Hub based gas prices offsetting the higher shipping costs.

Comparing the growth of the gas markets in Asia with those of Europe and North America, there exists an anomaly in terms of the prevalent prices. While the increased share of shale gas in the US has overturned the scarcity of the fuel and has therefore brought prices under control, the Europeans have managed to stabilise gas prices in their patch with increased gas-on-gas competition which has allowed them to re-negotiate their long term contracts by using market aligned benchmarks for imported LNG. With diminishing prospect of US receiving LNG exported out of Middle East and North Africa, the sellers have had to show the flexibility to sell surplus LNG closer to Hub based prices. The effect of these pricing changes, however, have had little or no effect so far on the Asian contract gas prices and are also yet to see the flexibility being accorded to them in terms of the structure of their contracts.



Source: BP Statistical Review of World Energy, June 2015

This price gap between Asia and the other LNG using markets comes at a time when new LNG projects are expanding total delivery capacity by an additional one-third, with most of that incremental capacity specifically targeting the Asian market. Further expansions are being planned by US, Australia, Russia and East Africa. The reason for this focus is no doubt driven by ongoing surge in gas demand in Asia which is expected to absorb almost half of incremental global consumption over the medium term until 2019.

4.2 Factors Influencing the LNG Market

As the natural gas markets around the world mature with respect to both organisation and structure, the effect will be seen in terms of energy stability and security. This in turn will further add to more robust and efficient supply arrangement allowing greater flexibility and lower costs at both producer as well as consumer end. External factors such as government policies on environment, nuclear power will also play their part in extending the role of LNG based natural gas consumption in energy starved countries. Some of the key drivers of this continuing change are described below: -

4.2.1 Unconventional Gas

It is estimated that about a third of the global natural gas resources are in the shale formations. Rapid advancements made in the extraction techniques have allowed unconventional gas reserves such as shale gas and coal bed methane to boost the economically available gas reserves around the world. There is a large variance between availability of these reserves in many parts of the world and how successfully they have been utilised. To add to this, there is also the uncertainty between theoretical availability of such resources and the reasonable estimates of their actual recoverability. Shale gas has grown fastest in the US and now account for more than 45% of its total dry natural gas production. China is another shale gas producer outside the US as it pushes to increase share of unconventional resources to meet its energy needs.

The rise in shale gas development, along with CBM/CSM and tight gas extraction, has come about with breakthrough in exploratory and production techniques such as 3 and 4 dimensional survey as well as advanced horizontal drilling and hydraulic fracturing (or fracking). These have not only allowed greater access to previously untapped resources but fine tuning of these techniques have increased the production efficiency to a new level. Whereas survey improvements have enabled success rates of exploratory drilling, the advances in fracking have allowed continued improvements in field productivity resulting in tremendous cost savings. The culmination of these improvements has seen US total proven reserves more than doubled from their lows in 1999.

As the largest gas consumer in the world, this tremendous boost in US gas production has had a profound effect on the global gas markets and the LNG trade in particular. From the position of a tight gas supply and demand balance met with increasing LNG imports, the shale revolution not only eased the supply pressure on US with corresponding reduction in benchmark domestic prices, the abundance in production is allowing it to consider possible LNG exports with a number of projects at various stages of development at hand. This has disrupted the global LNG flow such that incremental capacity in MENA region that was to supply the US is instead now being offered into Europe. And with increased domestic supply, US itself can now sell LNG into the lucrative and fast growing Asia-Pacific region.

4.2.2 Coal Bed Methane / Coal Seam Methane

Methane trapped in coal beds or seams is another form of unconventional natural gas. The methane is extracted through a drainage process by drilling either vertical or horizontal wells into the coal seams and water pumped out to reduce the pressure and thereby releasing the adsorbed methane which is then collected via gathering system and hauled for utilisation as a supplement or a replacement for conventional natural gas. CBM is largely produced in the US with its share approaching 10% of the total US gas production.

A unique example of CBM's relevance to the LNG industry is Australia where three world scale LNG liquefaction and export projects have been built near Gladstone in the Queensland state at a cost of around $70 billion and pumping more than 25 MT of LNG per year. The first of these projects owned by BG / Shell has already commenced operation with the other two soon to follow. Just like the shale gas example in the US, these coal seam gas based LNG plants are showcasing the technology that now allows stranded unconventional dry CBM resources to be utilised to boost the flexibility in delineating gas resources for LNG supply.

4.2.3 Floating Technologies

LNG projects have traditionally been highly capital intensive requiring long term firm contracts as well as long lead times. In order to bring costs under control and allow flexibility in construction and utilisation, floating offshore facilities (FLNG) have often been proposed for not only liquefaction but also regasification at the utilisation end.

Integrated oil majors such as Shell have specialised this technology besides smaller independents which allows them to keep the costs under control while allowing flexible service offering. The big advantage with FLNG is the certainty and better management of upfront project costs with minimal external influences as the construction is typically carried out in a close environment of a shipyard with shorter lead times.

Currently shipyards in Korea followed by Japan see a lot of construction work in connection with the LNG carriers while floating vessels with regasification facilities called FSRUs (Floating Storage and Regasification Units) may be built in South Korea, Singapore and Malaysia. Floating Production, Storage and Offloading (FPSO) vessels have been used in the oil industry for some time now. Use of FLNG is pretty much dictated by the same criteria such as a stranded offshore field and high onshore liquefaction costs. While logistics may often dictate whether to choose FLNG or an onshore LNG facility, often external factors such as political influences or even fiscal terms may play a major role such as the Sunrise LNG development in the Timor Sea north of Australia. The first FLNG facility is to launch in 2015 but a number of new projects are currently being planned or executed such as the one in Malaysia for its offshore Kanowit Kumang project in 2016.

Floating regasification is a fast growing market with more and more countries looking to bring in LNG import capabilities. The reason why FSRUs would be used in preference to the traditional onshore regasification facilities is the shorter lead times allowing recipient countries to bring online such facilities very quickly. It is also useful in situations where the regasification arrangement is to last on a temporary or short term basis with flexibility in duration of their use. Floating technology therefore allows avoiding capital expense with regasification service paid for as an operating expense, reducing the project costs and easier financing. Since their launch with the first FSRU in UK, more than a dozen of such vessels are now deployed in various countries including Pakistan.

4.2.4 Capacity Expansion

We have seen an unprecedented level of new activity in LNG business over the last few years on the back of Asia's insatiable demand for growth matched by the shale gas revolution in the US as well as Australia's big leap forward with multiple CSM to LNG projects and Canada's intent to join the LNG exporting club in the near future. The global trade is expected to add another one-third capacity by 2019 to 450 bcm (from the 2014 level of 333 bcm). The overall utilisation rate of the current nameplate capacity stands at roughly 80% due to a number of reasons but mainly resulting from feedstock constraints as domestic gas is diverted to meet rising domestic demand.

The new east coast LNG plants coming up in Australia have all got 90% of their nameplate capacity tied up in long term contracts with Asian buyers but that also means there is provision for them to sell some LNG cargoes in the spot market. Historically, the spot market has not been very liquid with only less than 5% of the total LNG volumes being traded under non-long term deals. Since 2006, however, there has been a growing trend of relying on short term deliveries to as high as almost one-third of the entire LNG trade. This can be attributed to a number of factors such as: -

- LNG contracts allowing destination flexibility instead of the point to point arrangements that were typical in earlier long term deals.
- The number of participants has already increased with more and more buyers and sellers entering the LNG trading arena. The global regasification capacity has also increased allowing diverse markets the ability to receive and utilise LNG for the first time.
- Perhaps one of the biggest factors in dictating higher reliance on spot deals is the disparity that potentially exists between the long term LNG prices and the volatile spot prices. On the back of softening oil prices, spot market prices are quick to adjust accordingly whereas the contract prices carry a lag and therefore create a disparity between the short and longer term prices and a commercial incentive to rely on spot deals.

Historically the LNG shipping capacity has tracked the liquefaction capacity well as long term LNG supply contracts prevailed. However from around the mid-2000s the two have started to diverge with more ships ordered resulting in faster shipping capacity growth. With increasing shipping capacity it is getting easier to carry long haul cargoes under shorter term deals therefore allowing global LNG trade to grow between distant regions.

4.2.5 Demand Growth

Continuing economic growth in Asia is expected to keep driving the increased demand for LNG. Some estimates indicate a near doubling of energy demand across Asia. While the Chinese energy demand has already surpassed that of Japan as the second largest economy in the world, the aggregate demand increase from the rest of Asia outside China, Japan and India is likely to exceed the demand from any of these three major countries. Together with infrastructure growth and improving LNG pricing and flexibility, the LNG demand in Asia will continue to be a major driver for the global LNG market.

CHAPTER 05

Development of the Market Structure, Hubs, Contracts and Prices

5.1 Long Term Deals

The initial LNG supply was a fairly linear setup with domestic gas resources tied to a liquefaction plant which was supplying LNG that was received and regasified at the import terminal belonging to the buyer. To underpin this arrangement was a long term deal overseen by a financial institution to last for typically 20 years with price adjustments indexed to oil. The argument in its favour was the firmness of sales for the seller and an assurance of security of supply for the buyer. The ownership structure was such that gas belonging to the seller would be sent to the liquefaction plant, also owned by the seller. This classic one dimensional supply chain worked well for two of the largest LNG buyers, Japan and Korea and still continues to be the case for most of the LNG sold into Asia-Pacific.

5.2 Start of the Short Term Deals

The shale gas transformation that occurred in the US had a significant impact on this traditional LNG model as the US which was shaping up to be a large LNG importer but instead started running surplus in domestic gas production. While spot cargoes were being sold well before this transformation, the net effect of the withdrawal of North America as an LNG importer meant all that capacity that was brought up to supply this LNG, had to find a new market. As Qatar was looking to sell almost a third of its new LNG plant's volumes to the US, most of that had to be redirected to Asia with some continuing to be delivered into Europe. Both the seller as well as the buyer showed flexibility to allow these volumes to be absorbed alongside the longer term contracts under shorter / spot arrangements but still priced based on oil. The traditional setup of point to point LNG trade with destination specific deals were now being challenged by allowing deliveries to be redirected, allowing LNG portfolio setup and optimisation.

5.3 LNG Projects Commercial Structure

The ownership model also started seeing some variations from around the late 90s. The initial structure of vertical ownership was modified to allow liquefaction plant to be setup and operate on a tolling basis. This meant that more would be sellers could offer LNG without tying up capital in liquefaction asset and instead pay a service / capacity fee for the privilege to liquefy their gas based on demand.

The upstream Joint Ventures (JVs) also started seeing changes whereby one or more of the participating producers could buy a part of their own gas produced to run their individual portfolio with flexibility to choose where they sell / deliver their gas. Some large oil companies as well as aggregators / traders have since emerged who maintain an LNG trading book carrying LNG supplies from various sources and deliveries into different zones / regions based on price arbitrage between them. We can broadly classify the different project structures prevalent these days on the basis of ownership and its transfer along various elements in the LNG supply chain such as: -

- The traditional approach where liquefaction is an integral part of the upstream JV with each partner contributing their share of the project and then either market collectively or take individual share as equity gas (LNG).
- A bundled approach where the LNG project itself organises feedstock gas into the plant and sells the LNG output either with shipping (Delivered Ex-Ship, DES) or the buyer organises its own shipping (Freight On-Board, FOB).
- The tolling arrangement where the plant has no involvement in either upstream or downstream activities and only looks after the chilling of the molecules that are run through the plant on a fixed capacity charge plus a throughput charge. The capacity charge is fixed on a 'ship-or-pay' basis to allow the plant owner a guaranteed return and the user a secured right to use the contracted capacity. While this is a very flexible arrangement, it does require hands on involvement in terms of organising the gas and finding buyers as well as organising shipping to complete the LNG chain.

5.4 LNG Buy / Sell Contracts

LNG contracts have also evolved since the time when they were similar to the long term Gas Sales Agreements (GSA) specifying the quantities, prices, escalation regime, life of the contract or duration and transportation arrangements etc. Just like the GSAs they carried a take-or-pay clause that ensured a guaranteed volume offtake to underwrite the investment and ensure the buyer of secured LNG supplies into the future. As the contracts were typically signed to launch a new supply arrangement, there was often a build-up profile to specify lower / flexible quantities at the start to allow the buyer to set up and build the market for the new resource. In the absence of any other pricing reference, the price of LNG was pegged to oil as an already established international energy commodity.

Variations to the original contracts have largely focused on the pricing regime as the markets evolved in various regions and with increasing gas-on-gas competition. As the contracts have faced more and more pressure from competing sources of essentially the same fuel, the sellers have shown more flexibility to negotiate other benchmarks such as Hub based variation which will be discussed later. The other critical area of destination inflexibility with the original point to point contracts has given way to variations that allow LNG cargoes to either be resold or redirected to a new destination. Again as with prices, most of this flexibility has occurred in regions where LNG has faced competition such as Europe but is gaining popularity especially with shorter term or spot deals. Some sort of price re-negotiation can occur every few years by either the seller or the buyer citing change in the operating environment. Although this provision, when allowed, can typically be triggered every 3 or 4 years but can also be requested earlier based on circumstances.

In the light of increasing global volumes of traded LNG and with greater number of LNG buyers with diverse needs, the LNG suppliers will need to show more flexibility and allow more accommodative terms. The push is especially gaining momentum in Asia-Pacific region where most of the growth in trade is occurring.

5.5 Market / Hub Development

A Gas Hub can be defined as a place where buyers and sellers exchange the ownership of natural gas. The participants at the Hub can be producers, energy utilities, traders, large industrials or even financial players. It facilitates trade between the buyer and seller in a transparent manner, allowing competitive and efficient market to develop, with the price of gas reflecting the balance between supply and demand.

The process to eventually establish Gas Hubs perhaps started with the competition reforms to break up the monopoly businesses running the gas industry and to encourage contestability in each of its constituent elements. The unbundling of services and separation of infrastructure from retail sales allowed the infrastructure to be accessed by third parties in a non-preferential manner and with objective / fully transparent charges. These gradual changes in Europe, USA, Canada and Australia through deregulation allowed competition between multiple supply sources / market participants resulting in downward pressure on prices and transparency and liquidity to the gas markets.

The National Balancing Point in the UK is a virtual Hub created by the Network Code in order to promote the balancing mechanism detailed in the Code. It is where shippers nominate for buying and selling gas which is then used by National Grid as the system operator to balance the system on a daily basis.

Although the NBP was created by the Network Code purely in order to allow the physical balancing of the system, it rapidly evolved as a trading point too. Traders had confidence in buying and selling gas on a standardised basis at the most liquid point in the UK's high pressure transmission system. The use of the virtual hub allows all sources to be treated equally with no consideration to their physical location and to compete purely on the basis of their prices. The trading which used to be on a bilateral basis now includes Over-The-Counter (OTC) standardised trades as well as exchange traded instruments such as Futures contract. From an infrastructure point of view, the liberalisation of the gas market has had a profound impact on the connectivity and depth of the market such as a number of additional pipelines to the UK, new LNG receiving terminals, NTS upgrades and a major upgrade to the IUK pipeline[6]. The LNG regasification capacity itself has grown to a level where it can meet more than half of the UK's gas demand. All this flexibility means that, given the right price signals, the UK should attract LNG cargoes, either for its own demand or to transit through its system for its interconnected customers.

The Henry Hub in the US is a physical Hub with interconnected pipelines, both within and across various states and effectively reaches out to the entire gas producing and consuming centres across the US. Because of its high volume transactions and liquidity, it is used as a delivery point for NYMEX Futures contracts as well as quoted as a reference for buy / sell contracts. With the growing role of the shale gas, the activity and prominence is starting to shift towards Shale rich regions and hubs such as the Dominion South in Pennsylvania where gas trades now overshadow Henry Hub. However, Henry Hub is still quoted internationally as well as forms the basis for US gas futures.

An interesting observation can be made by looking at related hubs such as those in Europe. Even though the price escalators work differently across the continent as well as each hub carries different liquidity levels, the correlation between hubs tends to get stronger with time. This is quite significant and highlights one of the main benefits of running efficient markets - the price discovery process allows for the arbitrage to rebalance markets and in the process, either remove the price anomalies or clearly delineate the requirement to invest in infrastructure and connectivity.

[6] Patrick Heather, The Evolution and Functioning of the Traded Gas Market in Britain, 2010

CHAPTER 06

6.1 Pricing LNG

Pricing in LNG contracts is typically linked to an energy index. Initially, when the first of the long term deals were being negotiated, oil was already a mature market that allowed the ease of international benchmarking and price risk management. As such, oil was frequently used for LNG price indexation. Gradually with development of gas markets and competing gas supplies, other indexes have been developed and adopted.

We can broadly classify LNG pricing under three basic mechanisms: -

- **Hub Based Pricing**: where a gas trading hub establishes the price based on bids / offers by the participants to buy or sell physical, futures or even both type of contracts for natural gas.
- **Oil Linked Pricing**: which involves using crude oil and / or oil products pricing benchmarks are used as a reference point. On the basis that all these fuels have an energy content which is used to convert into heat during utilisation, we can derive the value of LNG with reference to oil or products. In simple terms, if LNG was to be priced at par with oil then using heat content of LNG which is 1/6th that of oil we can derive the LNG price as 0.17 times that of oil.
- **Hybrid Pricing**: Some contracts can even have a combination of both Hub(s) as well as oil benchmarks to reference LNG price against. In such cases a formula is negotiated using different weighting assigned to various benchmarks, based on their relevance to both buyers and sellers.

The formulae used in LNG contracts, however, can be very complex and varied, using not one but perhaps a basket of crude oil / oil products for reference or a combination of hubs. They can specify floor and cap for risk management and to manage volatility that can be experienced with international benchmarks.

With such a wide variety of pricing mechanisms available and deployed, it is no wonder there is no universal approach to it globally. It can however be said that there are common features with prices within a certain region which is largely driven by local and regional factors as tabulated below.

LNG Price Indices

Region	Common Benchmark(s)
East Asia	JCC (Japan Customs-Cleared Crude) oil
Mainland Europe	Crude oil, oil products, electricity etc.
United Kingdom	NBP (National Balancing Point) Virtual Hub
United States	Henry Hub, Physical Hub

In Japan and Korea, the two largest LNG importers in the world, the traditional practice has been to accept oil price indexation. In the absence of any other markers available to price gas against, the practice is continuing with regard to short term/spot as well as long term contracts. Following the oil price surge and the Fukushima nuclear disaster requiring very high LNG contribution in Japan to substitute for nuclear energy, the LNG prices since 2011 have remained very high in this region and have clearly diverged from the Hub based prices in the UK and US.

The trend has only reversed in late 2014 with oil prices starting to come off and with new LNG plants coming on in 2014/15.

Gas markets in Europe mainly rely on pipeline imports to augment their supplies with LNG used as a marginal source whose share has been falling for some time now due to lower demand. As pipeline contracts for gas supply into Europe were linked to oil, the same applied to contracts for LNG. In recent years though, hybrid formulae have been used which involved alignment with trading hub pricing to reflect the state of better inter-connectivity within European gas market.

Both UK and USA rely on Hub based pricing through their respective hubs, NBP and HH. With gas on gas competition, the market runs an efficient balance between supply and demand to determine a current price that reflects the scarcity or abundance of gas supplies against the prevailing demand. Significant growth in the number of import terminal and the corresponding regasification capacity has allowed UK to absorb a far greater share of the Qatari LNG build-up and keep Hub prices in line with the alternatives. Similarly in the USA, the rapid rise of shale gas have continued to put downward pressure on Hub prices and with continuing growth in domestic production, the prices are forecast to stay low. This prompted a new wave of LNG export projects to capitalise on the price differential between the Henry Hub and the Pacific region. In summary, we can say that a hub based price is a better way of determining the prevailing value of LNG as a commodity in that region but does require certain ground work before it can happen. Things like deregulation, allowing markets to operate freely and with improved liquidity and necessary infrastructure to support physical movements such as pipelines and storage etc. are the pre-requisites to allow efficient and dynamic markets to develop and the hub based pricing to work.

6.2 Pricing Trends

Benchmarking LNG contract prices against different indices has resulted in different price paths and as a result, systematic arbitrage spreads between regions, especially between Asian oil linked prices against others.

The typical pricing formula in an oil linked contract can be expressed in its simplest form as follows: -

LNG Price = Parity Factor x JCC + K

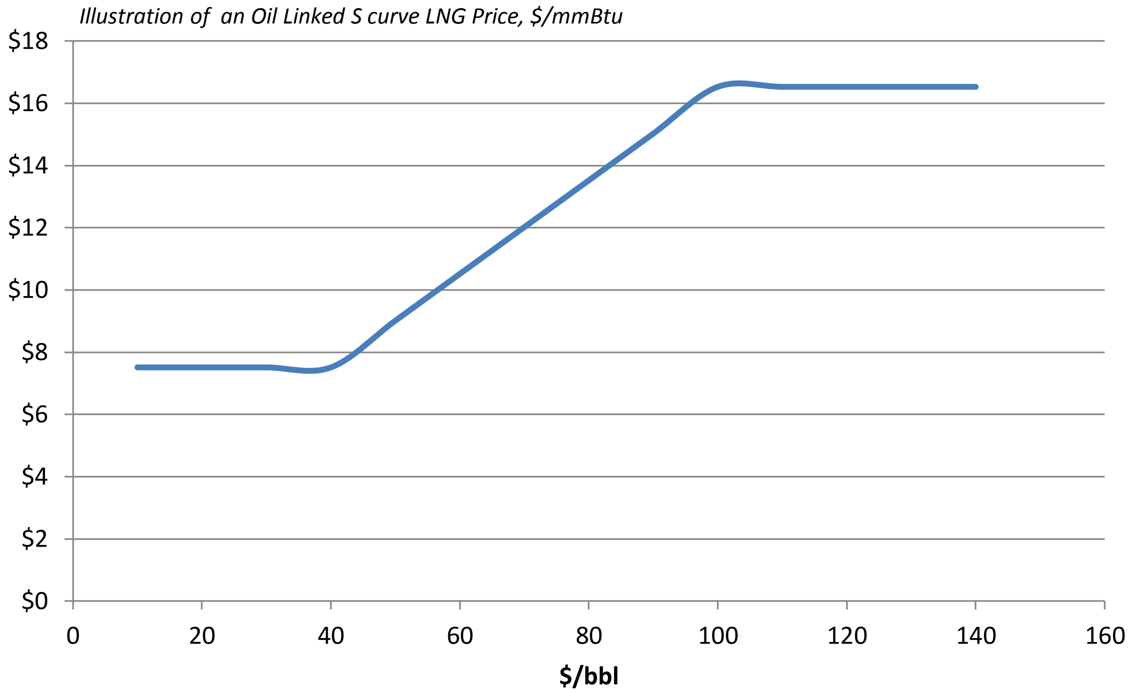
Parity Factor is a function of the ratio of gas to oil using heat content. This can be tweaked based on any discount negotiated between the buyer and seller. As gas carries a sixth of the energy of oil, at no discount or 100% crude oil parity, the factor will be 1/6 = 0.167. If a discount of 10% is allowed on crude oil price, the corresponding factor would be 0.15. The other factor K is a constant that generally relates to approximate shipping costs expressed as a $/mmBtu value.

The following table illustrate the relationship between JCC and LNG prices at various discount levels, assuming K at 1.5: -

Indicative LNG Price using JCC Benchmarking

Parity Level	100%	90%	85%
JCC @$100/bbl	18.20	16.53	15.70
JCC @$70/bbl	13.19	12.02	11.44
JCC @$50/bbl	9.85	9.02	8.60
JCC @$40/bbl	8.18	7.51	7.18

The chart below illustrates the 90% scenario in the table above with a cap and a floor, known as the 'S' curve. Such an arrangement allows protection for both buyer and seller in the event that volatile prices either increase beyond a certain limit or drop below a sustainable level.



The very large difference between LNG prices corresponding to movements in crude oil explains the spread we saw after the 2011 between UK / US prices and those paid by Japanese buyers. As Japanese prices have been tracking higher based on elevated crude oil prices, both UK and US prices have either stabilised or softened as in the US due to rise and abundance of shale gas.

Assuming a US Henry Hub price of $4/mmBtu and another $6/mmBtu for a netback including liquefaction of around $10/mmBtu and a landed price into Japan of around $12/mmBtu would have been much cheaper than the contract price paid by Japan. It is therefore no surprise that a number of LNG export projects have been proposed in recent times with some brownfield developments quickly converting the existing LNG import terminals into export facilities with a total LNG capacity of almost 44 MTPA under construction. The same arbitrage has been responsible for a gradual increase in the number of spot LNG deliveries being diverted from continental Europe to Pacific region resulting in short term / spot trade to increase to more than a quarter of the global LNG sales. Besides US, both Qatar and Australia have continued to augment their LNG export capacity especially Australia where almost 58 MTPA worth of new LNG capacity is either completed or nearing completion.

While all this capacity augmentation has been continuing, the weakening oil and gas demand and a soft outlook has dramatically turned the oil prices since late 2014 with recent benchmark prices such as WTI crude dropping to below $40/bbl. As can be expected, this has had a similar downward effect on spot LNG prices too with recent spot JKM prices for October ’15 delivery dropping to as low as $7.6/mmBtu. Although the long term contracts carry a lag before prices are adjusted based on prevailing oil prices, the contract prices have been gradually softening since the start of 2015 with prices continuing to come down to where the spot LNG prices are, as crude oil price looks set to stay at its current level in the short and medium term.

6.3 LNG Price Outlook

At the height of the LNG price disparity in 2011/12, the Japanese have been advocating a move away from the oil linked pricing to a new benchmark such as the Henry Hub in the USA. Some contracts were signed with Henry Hub pricing with Asian companies increasing their upstream interests in US LNG but the lower price turnaround since 4Q14 has removed that urgency and the commercial driver to force an immediate change.

On the other hand, most of the new capacity brought online recently was based on favourable project economics using higher Asia-Pacific prices at that time. To complicate things further, almost all the new projects initiated in Australia saw considerable price overruns due to higher wage costs, delays for competing projects and exchange rates etc. which made them even more dependent on higher LNG prices to breakeven. It has been estimated that the capital charge for these projects is almost 3 times the cost of Qatari LNG. This provides a new challenge to the proponents of any new LNG project to consistently lower their capital costs in the wake of lower Asian prices which are likely to stay at these lower levels for quite some time.

In terms of the future outlook though, it can be concluded that the gas markets are likely to continue their growth, especially in Asia Pacific and in the wake of lower spot prices that seem destined to stay for a while as more and more interconnection between markets and the extended reach through technology. As gas markets further develop in Asia encouraging competition between sources and liberalisation of the energy markets, trading hubs can develop where gas will be traded and priced on its own rather than having to be benchmarked against other fuels / indexes. Both Singapore and Japan have been vying to set up an exchange for LNG trades but with little or very limited progress so far because of the long term nature of the contracts with restricted shipping terms, while the spot market is illiquid and lacks transparency. Such a development of local gas trading hubs will also reinforce the bargaining power of the buyer and allow contractual flexibility to flourish.

For the sake of current modelling, it is appropriate to assume that while oil indexation will continue to have a role in all the new supplies into Asia, increasingly there will be contracts set up with Henry Hub used as a benchmark, either on its own or as a hybrid with an S curve limiting the risk and exposure for both the buyers and sellers. With increased supplies, especially spot sales, the LNG prices will continue to narrow the gap between regions. The process that was started to define new basis for LNG pricing will continue but the current soft oil price environment means there is no urgency for the buyers as regional prices are already showing alignment, regardless of the benchmarks used.

The other area that will see considerable focus is going to be LNG contract standardisation. With more buyers entering the pool requiring a diverse set of flexible parameters, there is a need to establish and maintain standard contract terms to streamline the negotiation and operation of future deals. The Association of International Petroleum Negotiators (AIPN) released its model LNG Master Sales Agreement (MSA) in 2009 for spot sales on DES basis. This is a good start and should see further work done to not only facilitate easy physical trading but also allow secondary markets to develop for better risk management and market depth.

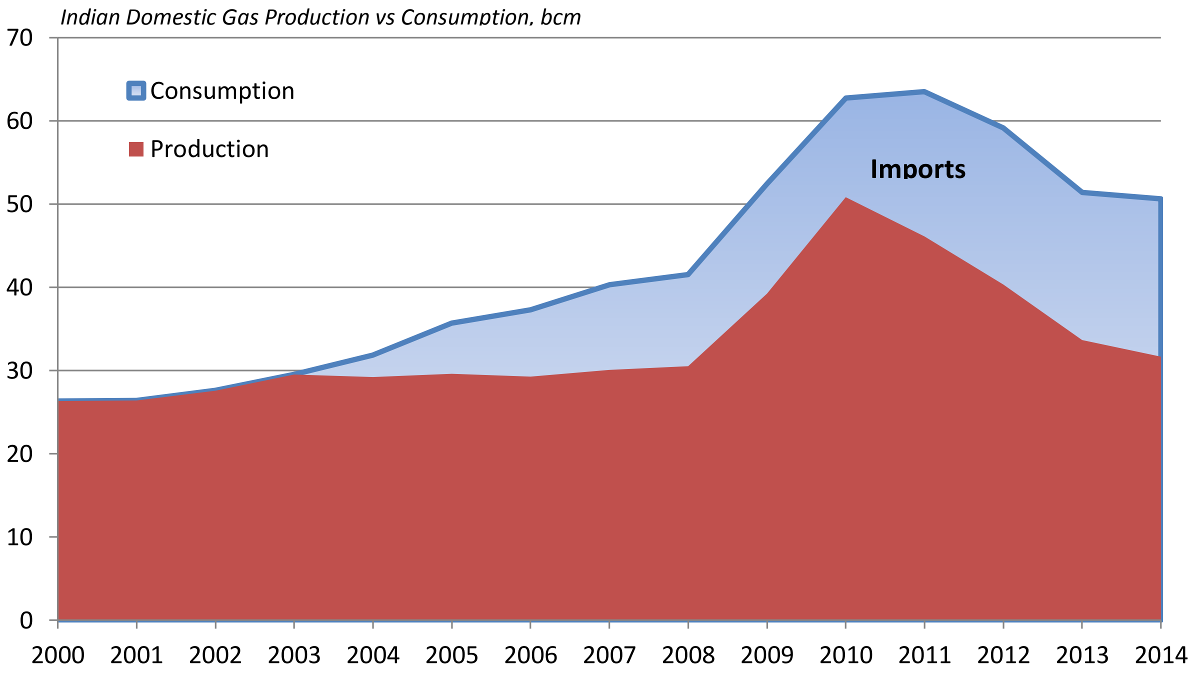
CHAPTER 07

7.1 LNG Market Trends in South Asia

With natural gas as the fuel of choice in South Asia, the governments of all the member countries with domestic gas supply, Bangladesh, India and Pakistan have been actively seeking to bolster their supplies through both pipeline as well as LNG imports with mixed progress so far. With their combined share of global consumption making them collectively the fifth largest user in the world, as a group they are quite significant to global gas trade with a falling domestic production and increasing reliance on gas imports. The following section is focused on looking at each of these countries individually and analyse their market and future trends.

7.2 India

India has perhaps been the most active of all the south Asian countries in terms of its reliance on gas imports to meet its rapid demand growth. The push for gas via continuing policy initiatives since the mid-1990s together with regulated low prices and improved infrastructure have seen demand far outstrip supply. And while domestic gas supply did get some support, the rate of growth has been such that India has been increasingly reliant on gas imports to match its demand.



Source: BP Statistical Review of World Energy, June 2015

In terms of sectoral consumption, the power and fertiliser together take up almost 60% of the entire gas demand with large industrials local distribution and Industrial & Commercial (I&C) customers taking up the rest. Gas utilisation often is a function of the availability of transmission and distribution infrastructure and as such, demand has been concentrated in the north western states along the fully contracted Hazira-Vijaipur-Jagdishpur (HVJ) pipeline owned by GAIL which has been further augmented to boost its capacity. The other pipelines are either owned by Gujarat State Petronet Limited (GSPL) or Reliance Gas Transportation Infrastructure Limited (GTIL). Due to their limited geographical coverage, gas utilisation has remained localised in a few states such as Gujarat but expansion into new areas is being encouraged. The Petroleum and Natural Gas Regulatory Board (PNGRB) which was established in 2006 as the downstream regulator, has streamlined the approval process together with tariff and capacity bidding procedures. After the gas pipeline policy was announced in 2006 which called for greater private sector involvement in the transmission sector, a number of new pipeline projects have been proposed which may not only address the physical bottlenecks but would eventually see gas supply being extended to previously un-served regions.

While plans are afoot to deal with pipeline network limitations, the ambitious plan calls for a major increase of natural gas in India's primary energy mix by 2035[7].

Indian Primary Energy Mix, MTOE

Source	**2014**	**2035 Forecast**	**+ / -**
Coal	360.2	618.0	72%
Oil	180.7	356.0	97%
Gas	45.6	154.0	238%
Hydro	43.5	71.0	63%
Nuclear	7.8	48.0	515%
Total	637.8	1,247.0	96%

Source: Source: BP, IEA

All the major users of gas including power, fertiliser, I&C and residential are expected to contribute to this demand growth. Demand growth in power is to be driven by substitution of coal and a corresponding increase in gas infrastructure and supply. Similarly, demand from fertiliser industry will continue to grow with higher agriculture demand as well increased cost of imported urea justifying larger domestic production. The I&C market as well as residential sectors will enhance their share to take environmental benefits of clean burning gas as well as the ease and convenience of its use. In terms of robustness of demand, both power and fertiliser industries will continue to be sensitive to price of gas and that will see variability of imported gas volumes due to volatile international gas prices.

7.2.1 Gas Allocation Policy

As demand has far outstripped domestic gas supplies, the government has stepped in with an allocation policy which predetermines the priority to be allocated to a certain gas consuming sector. The policy has been revised from time to time and proposed changes made in Dec. '14 allows CNG transport and residential customers the top priority, displacing fertiliser plants who were previously allowed the first right over gas, followed by the power sector. The allocation priority entails any incremental demand from the priority sector, in this case the City Gas Distribution (CGD), are fully satisfied at the expense of non-priority sectors whose share is proportionately truncated because the domestic supplies are either stagnant or even falling.

7.2.2 Pricing Regime

There are two streams of natural gas pricing in India, The Administrative Price Mechanism (APM) and a non-APM. The APM applies to domestic producers for gas sales to certain categories of customers such as power plants etc. The non-APM prices are typically higher and relate to production from New Exploration Licensing Policy (NELP) or pre-NELP fields as well

[7] IEA, World Energy Outlook, 2011

as imported LNG. The government is involved in setting all the prices with the exception of imported LNG which is based on international long / short or spot LNG contracts.

In order to simplify the process and to reduce the administrative burden and arbitrariness, the Rangarajan Committee came up with a new formula for the domestic price of natural gas by linking domestic prices to international benchmark prices. The formula was based on historical volume weighted average netback prices at the wellhead of all the LNG imports for the past 12 months, and the volume weighted price of the US Henry Hub, UK's National Balancing Point and Japan's Crude Cocktail price.

In a further revision to this formula, only hub based weighted averages for the past 12 months of 4 international benchmarks were used including, Henry Hub of USA, Alberta in Canada, National Balancing Point in the UK and Russian gas. Revised every six months, this approach ignores the actual price of LNG imports altogether which means a total disconnect between price paid for imported vs domestic gas. The price for November 2014 to March 2015 was $5.61/mmBtu under this formula which was revised down to $5.16/mmBtu in April 2015 as a result of global softening of hub prices since late 2014.

The government is also involved in subsidising directly or indirectly, two of the most important gas using sectors i.e. power generation and fertiliser. The size of the subsidy to fertiliser industry takes a heavy toll on government finances as gas is the primary input and represents major cost in producing urea. Similarly, if electricity charges are below the cost of generation, they represent another indirect cost to the budget.

7.2.3 Demand Outlook

The pace of Indian energy demand growth is expected to continue its rise well into the future. The fundamental driver will continue to be improved access to energy for a growing population whose per capita energy consumption is still very low at 0.58 TOE per capita against a world average of 1.8 TOE per capita. Given the anticipated magnitude of this increase in energy consumption, almost all the fuels will see a much larger contribution. For natural gas, the increase is almost threefold in its consumption by 2035 based on considerable lift in demand by all the consuming sectors.

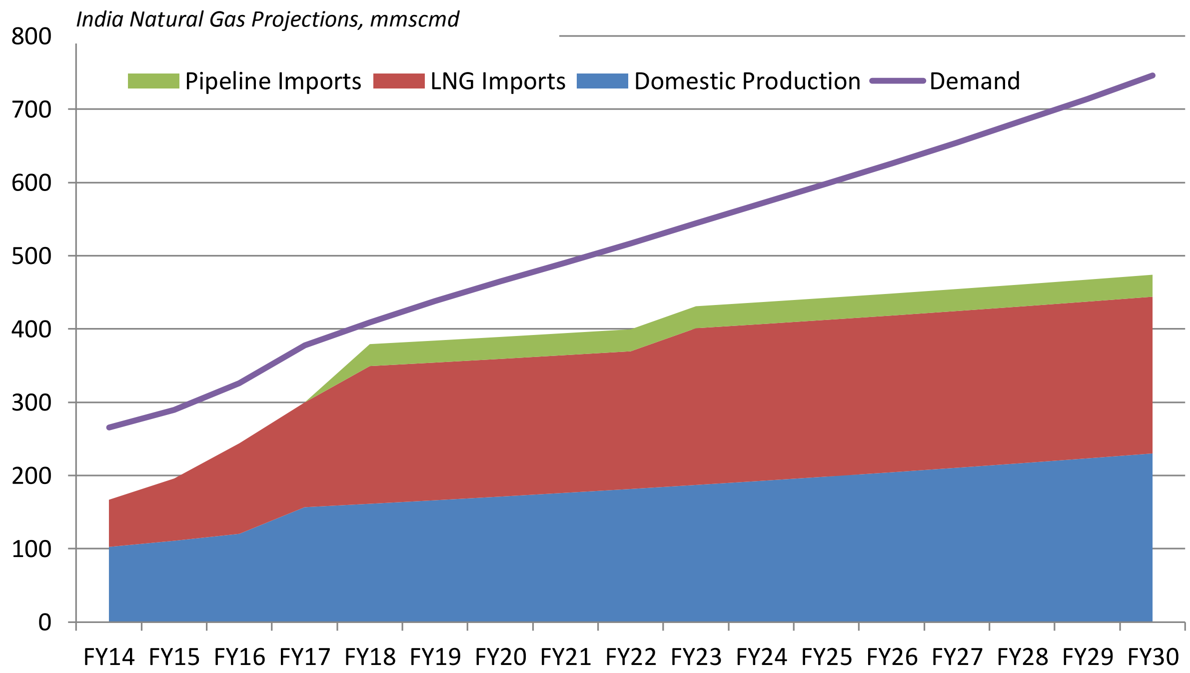
Power sector has been the largest gas consumer in India. The share of gas in overall generation fuel mix is close to 10% but this figure is influenced by availability as well as affordability of gas. As gas is competing against the traditional fuels such as coal, for large scale use the price of imported gas has to be low enough for a wider use. Similarly, with infrastructural limitations the use of gas can only be possible in generation units which can be supplied along the existing pipeline routes. The power sector growth plan envisages removal of these bottlenecks and with additional gas fired capacity the total demand is expected to increase its share by almost 40% during the forecast period to 2030.

The fertiliser industry is also a large gas user and one of the priority areas under the government's allocation policy. The demand however is very price sensitive in this demand segment as gas feedstock makes up more than 2/3rd of the operational costs. The growth in fertiliser is expected to be a bit restricted due to availability and access issues. While its demand is to grow in absolute terms, its share in overall gas consumption will likely drop from the current 26% to 15% by 2030.

The City Gas Distribution (CGD) sector is perhaps the most price resilient part of the gas demand. This includes the Natural Gas Vehicle (NGV) transport segment where CNG is used as a substitute for liquid fuels. With more and more networks being connected to future gas supply, the share of CGD's demand in gas consumption is expected to increase from the current 7% to 12% during the forecast period until 2030[8].

7.2.4 Supply Outlook

While gas demand has been rapidly growing, the domestic supply has seen its ups and down but largely has lagged behind with the result that India is increasingly reliant on gas imports to satisfy its requirement. Output from KG D6 field which showed a lot of promise at the start has continued to drop while the maturing Bombay High field is seeing its production plateaued. Expansion plans are underway but in the near future, the shortfall will continue to be addressed with higher LNG imports.



Source: Vision 2030 Natural Gas Infrastructure in India, 2013

According to the Vision 2030 energy modelling conducted by the Industry group in India, the supply / demand gap is even bigger based on 'Realistic' scenario which looks at potential daily unsatisfied demand against daily supply capability. The gap continues to get bigger and bigger as the domestic supply tapers off around the FY18 and the pipeline imports start via Turkmenistan to Afghanistan, Pakistan and India (TAPI) pipeline.

The chart is a good illustration of the fact that the current steps to deal with the supply / demand gap will definitely help in narrowing it around 2018 with the start of the pipeline imports as well as boosting the regasification capacity at multiple new and expansion projects lined up for LNG imports. The continuing growth beyond then, however, would mean there will need to be additional sources located or the supply inadequacy will again start to become an impediment to growth.

This may mean identifying as yet unknown gas import options such as new interstate pipelines and / or continuing to boost the LNG imports via new contracts as well as enhancing the receiving and distribution capacity.

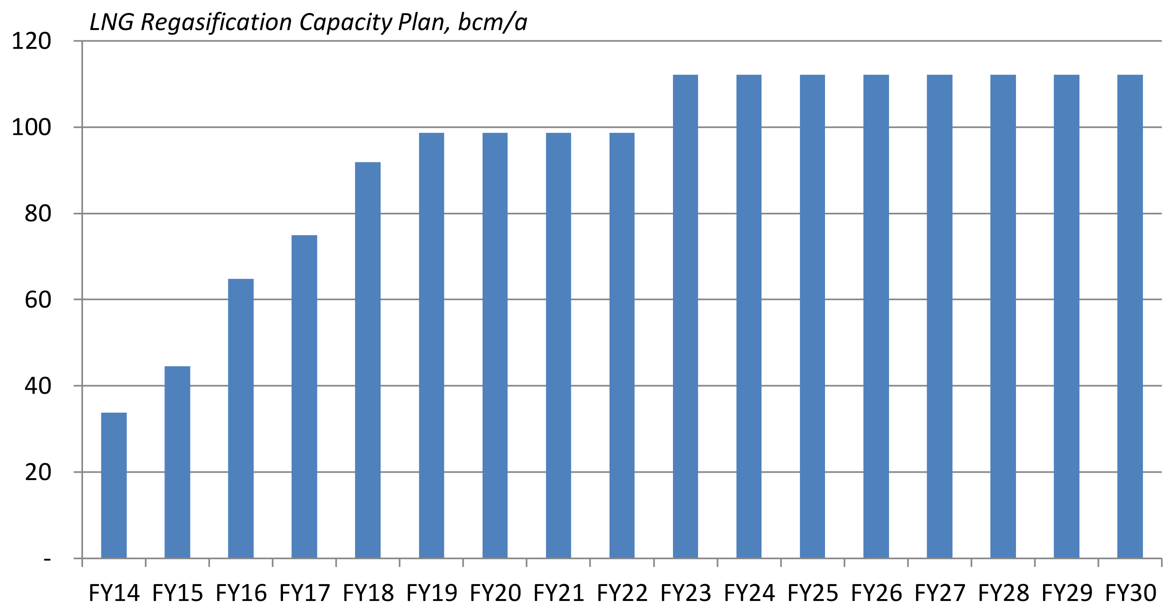
[8] PNGRB, Vision 2030 – Natural Gas Infrastructure in India

7.2.5 LNG Imports

India has been a net gas importer since 2004 and has a growing number of LNG import and regasification terminals to bolster the domestic supplies. A number of long term LNG contracts are currently in operation in addition to ongoing short term and spot purchases for top ups.

The mainstay of the LNG supplies has been the 7.5 MTPA LNG (10 bcm/a) 25 year oil indexed deal between Petronet of India and Qatargas. Petronet has further signed a 20 year agreement to import 1.44 MTPA (2bcm/a) of LNG from ExxonMobil's Gorgon Project in Western Australia and GAIL concluded a 20 year contract to buy 2.5 MTPA (3.4bcm/a) from Cheniere's Sabine Pass facility in Louisiana on an FOB basis with price linked to Henry Hub. A number of other deals are in the works which will bring in the additional LNG as and when more import and regasification capacity is brought online. Meanwhile, Indian firms have been actively seeking spot purchases to supplement contract deliveries. In the current environment where oil is trading at a heavy discount, the oil linked spot prices in Asia have created all the commercial incentive to seek a larger share of spot deliveries, sometimes even at the expense of deferred long term contracts whose price may still be higher.

India relies on two import terminals along its west coast to receive and regasify LNG. The Dahej terminal has a capacity of 10 MTPA (13.5 bcm/a). Gas from Qatar takes most of the capacity with the balance can be utilised for spot cargoes. The second terminal at Hazira is a 3.6 MTPA (5 bcm/a) facility owned by Shell and receives LNG under short term arrangements and on needs basis. The new terminal at Kochi is expected to receive its first LNG cargo via the Gorgon project towards the end of 2015. There are several projects to not only boost the capacity of these terminals but to also set up new ones. Dahej terminal will increase its capacity to 15 MTPA by FY16 while Hazira is likely to increase to 10 MTPA by FY 17. The capacity augmentation plans as per the Vision 2030 projections are set out as follows: -



Source: Vision 2030 Natural Gas Infrastructure in India, 2013

7.2.6 Issues & Challenges

The unexpected drop in output from KG D6 has thrown open the question of domestic contribution to India's growing gas consumption. The field that was initially estimated to carry more than 9 tcf of gas reserves have seen a significant markdown to a low of about 1.5 tcf. Gas deliverability from the other major field Bombay High has also plateaued and unless major new finds are brought online soon, the share of locally produced gas will continue to fall.

The forecast supply modelling under the government's Vision 2030 has also set a modest pace of domestic growth of about 3% for the plan period until FY30 with its share of the total projected demand to fall below one third while the other two third to be met via pipeline and LNG imports.

This has proved quite challenging as gas fired power generation capacity, for example, that was to utilise growing domestic production is now exposed to the limited access and volatile import prices.

As a result of limited and shrinking domestic contribution, the share of imported energy is growing astronomically. Along with importing oil and gas (LNG), India has even started importing coal whose contribution has doubled in recent years.

An increasing reliance on imports raises the issue of supply security besides the uncertainty of price volatility which can be a challenge for the government in terms of the balance of payment and an impediment for the commercially sensitive areas such as power generation and fertiliser industries, the two major users of natural gas.

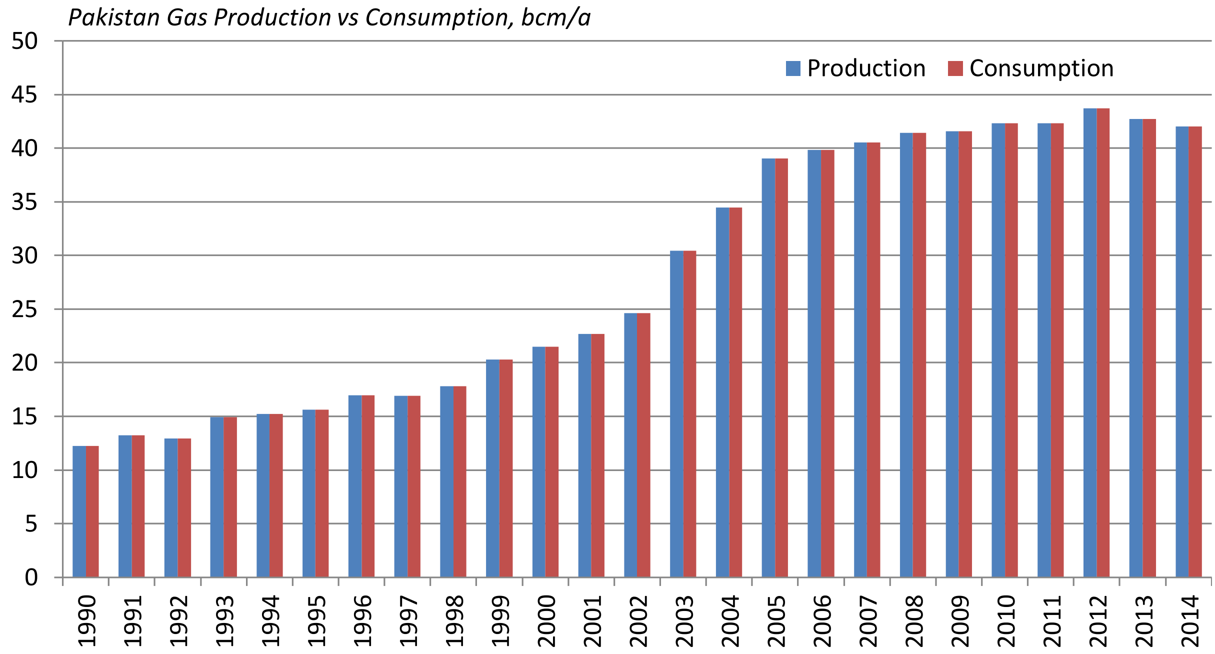
Pricing reforms have come a long way in India and after the 'arm's length' gas pricing approach; the process of simplified and unified price has gained significant ground. The current upstream price based on international hub based pricing has to some extent harmonised domestic gas price with typical market based prices paid in other regions. There is however a total disconnect with actual prices paid for imported gas and as such creates a barrier to run an efficient market.

On the downstream side too, the government prescribes the gas allocation rules which not only takes away the commercial incentive for the producers to find the most attractive market segment for their gas but also distorts pricing signal for the end users by regulating the tariffs and gas prices.

The extent and reach of the gas grid has been a major impediment to gas demand growth, especially in the southern and eastern parts. There are plans for a significant expansion of the transmission system which will need both public as well as private sector participation given the large investments involved. Regulatory certainty and transparency will ensure a successful involvement for all stakeholders by introducing Third Party Access on non-preferential basis and uniform tariffs will provide the competitive dynamism to set up a fully functioning gas market.

7.3 Pakistan

Pakistan is one of the most recent entrants to the LNG importing club and received its first cargo of LNG from Qatar in March 2015. Gas has remained the dominant fuel with more than 50% share in Pakistan's energy supply mix. From its early introduction in 1960s, the country has gradually built an elaborate transmission and distribution network which allowed gas to support all the sectors of the economy including residential customers via reticulated networks and the fast growing CNG as transport fuel.



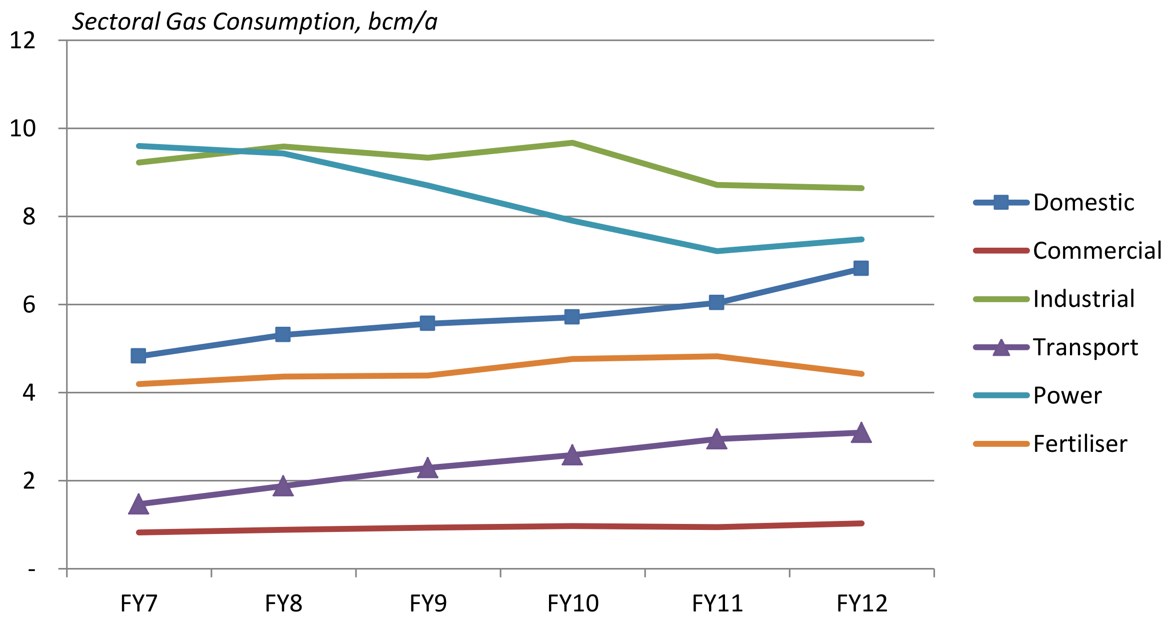
Source: BP Statistical Review of World Energy, June 2015

Gas production has steadily grown with growing demand at a healthy 5 – 6% annually but has flat lined or more recently, even dropped since 2013 on account of struggling domestic production failing to satisfy the rising demand. Majority of the gas in used in the Industry (27%) including heavy industries such as Steel mills, followed by power generation (24%) which is the most affected as a result of any gas supply constraints. The domestic sector is a sizeable 22% with more than 6 million households connected via distribution networks. The fertiliser sector which consumes gas for both its energy content as well as a feedstock, takes up about 14% of total gas usage while CNG for transport is the fastest growing segment at 10%.

A look at the growth of these sectors over the last few years indicates how the sectoral allocation has impacted an uneven gas consumption change in various areas. Since the time around 2007 when the domestic production plateaued, the only sectors who have registered a net growth are domestic consumers and the CNG transport sector, both are politically sensitive and are hard to restrain as it directly impacts the population in general.

Unfortunately this growth in CNG and domestic demand has come at the expense of the two major gas consumers, power generation and large industrials. As the timid growth in gas supply could not keep pace with the rising demand, it appears that more and more gas has been diverted from power generation and industry to lower the impact of supply shortfall on the masses.

The situation however on the ground is rather bleak with all the users essentially feeling the gas pinch even though gas allocation priorities have sought to minimise the impact on certain sectors of the economy.



Source: Pakistan Energy Yearbook, 2012

Faced with rampant load shedding of electricity and severe gas rationing, the government formulated the Gas Allocation and Management Policy (GAMP) which detailed the merit order for gas allocation to respective areas. Whether it has been the lack of administrative will or a logistical issue in its execution, the policy has been hard to implement and as a result the CNG industry which was one of the areas to be restricted, continued to grow at the expense of power generation which was then forced to revert to expensive fuel oil as an alternative.

In terms of prices, the government sets both the upstream and downstream prices for gas. The producer prices are based on a sliding scale using prevalent crude oil prices with a floor and a cap. Furthermore, a discount factor is applied based on the zone location of the field to incentivise exploration in high risk and high cost areas such as offshore basin. The Oil and Gas Regulatory Authority (OGRA) determines the gas prices based on the revenue requirements of the gas companies using their cost of gas, business operating costs and a prescribed return on asset. Similarly, the consumer's sale prices are fixed by the federal government under the OGRA Ordinance 2002 for each category of consumers which are then officially notified by OGRA.

As can be imagined, it is very hard to realistically determine the future demand outlook in the present environment with restricted access and a large unsatisfied demand. Some estimates such as those by the Petroleum Institute of Pakistan (PIP) place the current un-restricted gas demand to be as high as 59 bcm against the total gas availability of 40 bcm, indicating a potential unmet demand of 19 bcm.

Gas Demand Projections, bcm

Year	2013	2017	2022
Demand	36	59	77
Domestic Supply	36	40	41
Shortfall	-	(19)	(36)

Source: PIP Estimates

In the absence of any new supply or gas imports, the forecast shortfall is likely to grow to almost as high as the current demand levels.

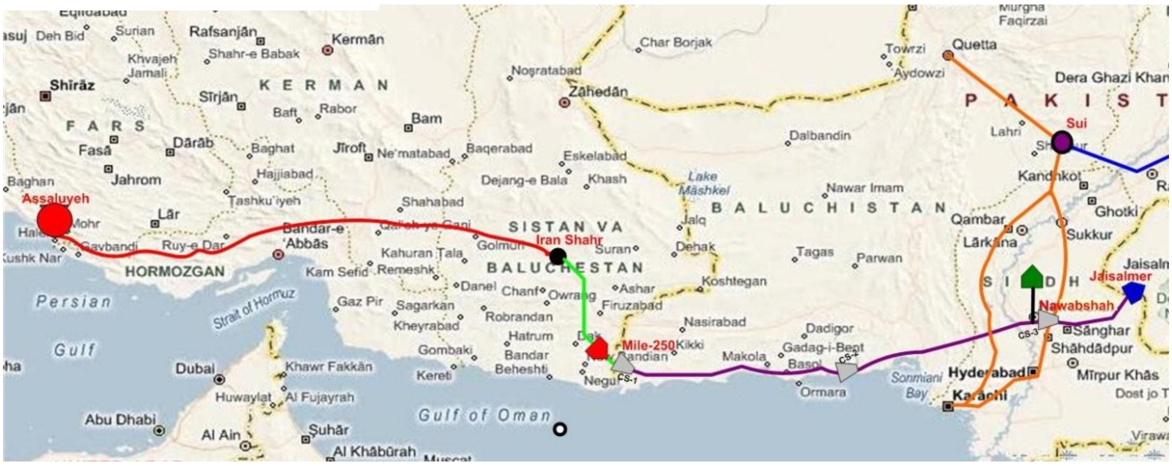
7.3.1 Gas Imports including LNG

Work on exploring various options to import natural gas via pipeline and LNG has been going on for a number of years. Despite several attempts and a flurry of activity at times with positive announcements, the pipeline projects have yet to materialise.

7.3.2 Pipeline Imports

The Iran to Pakistan (IP) gas pipeline was proposed in the nineties, to allow the South Pars gas field in Iran to supply gas via a 1,930 kms pipeline to Pakistan. Each side was to build their respective share of the total length, some 1,150 kms on the Iranian side and about 780 kms by Pakistan to hook into the national transmission system.

Iran Pakistan Gas Pipeline



The project hit a massive roadblock with the imposition of nuclear sanctions on Iran and while Iran did complete their part of the pipeline construction along their territory, no work could commence on the Pakistani side. Some progress was made in 2009 with signing of the Gas Sales Agreement (GSA) but the project is still held up. With the conclusion of the deal recently between Iran and the world powers, Iran is now expected to receive sanctions relief which will allow it to pursue commercial deals including the IPGP. The other big positive development has been the announcement by China to support completion of the Pakistani pipeline section thereby allowing the physical access for the gas to flow.

The IP is likely to be part of the larger and broader cooperation framework called China-Pakistan Economic Corridor (CPEC) which is a massive infrastructure initiative linking south western part of China with the port city of Gwadar. As part of this arrangement, Pakistan will build the section from Iranian border to Gwadar port while China will finish and integrate the rest of the length along the CPEC. Iran has also welcomed the Chinese involvement and it seems that progress on this project should start towards the later part of 2015.

The other pipeline initiative has been the Turkmenistan to Afghanistan, Pakistan and India (TAPI) gas pipeline which has been coordinated by the Asian Development Bank as a 56 inch and 1,680 kms pipeline linking southern Turkmenistan gas fields with Afghanistan, Pakistan and India.

Since 2004 when the project was first proposed, a number of agreements / MoUs have been executed but the project has so far struggled with any traction.

Turkmenistan Afghanistan Pakistan India Gas Pipeline

Recently, the four participating countries formed a consortium and Turkmenistan's state owned TurkmenGaz as the project lead with major investment while other parties contributing their share accordingly. The total volume throughput of 33 bcm/a will be split between Afghanistan taking 5 bcm/a while Pakistan and India receiving 14 bcm/a each. The $7.6 billion pipeline carries a 30 year GSA with sale price agreed at Turkmenistan border at roughly 12%Brent Crude benchmark and a transit fee of about $0.495/mmBtu for each leg along Afghanistan and Pakistan. The first gas is expected around 2018 as reports suggest that Turkmenistan has launched construction of the pipeline at their end.

The TAPI too has a few challenges to deal with. Besides the issue of adequacy of proven reserves to underpin supply, in addition to Turkmenistan's other gas sales commitments, is yet to be tested. The other challenge is with the pipeline route traversing along Afghanistan while security there remains precarious. The last one is the financial challenge as the project has been unable to involve an international major to participate which would also have boosted its technical prowess.

7.3.3 LNG Imports

LNG import projects in Pakistan have been touted since 2005 but have faced increasing level of uncertainties after a number of unsuccessful attempts. The LNG importation Policy in 2006 was to herald a new era of private sector participation in bringing as much as 4 MTPA LNG to support domestic gas production.

The complexity of setting up a new supply chain, lack of clarity and transparency in procedures and oil linked LNG pricing, all contributed to the stalemate with a number of attempts to kick-start the process was either thwarted by limited interest or irregularities being legally challenged in the courts. The supply gap, meanwhile, continued to grow wider resulting in more pressure to act.

In 2011, the government came up with a revised LNG policy which sought to offer some more flexibility in LNG based gas supply prices being unregulated for certain consumers. This saw some local companies entering the LNG space with setting up the groundwork to establish LNG import projects. In 2013 call for tenders by the government, two bids were received from Pakistan Gas Port and Engro Elengy Terminal Pakistan Limited. As the Gas Port bid was disqualified on technical grounds, the tender was awarded to Engro by default.

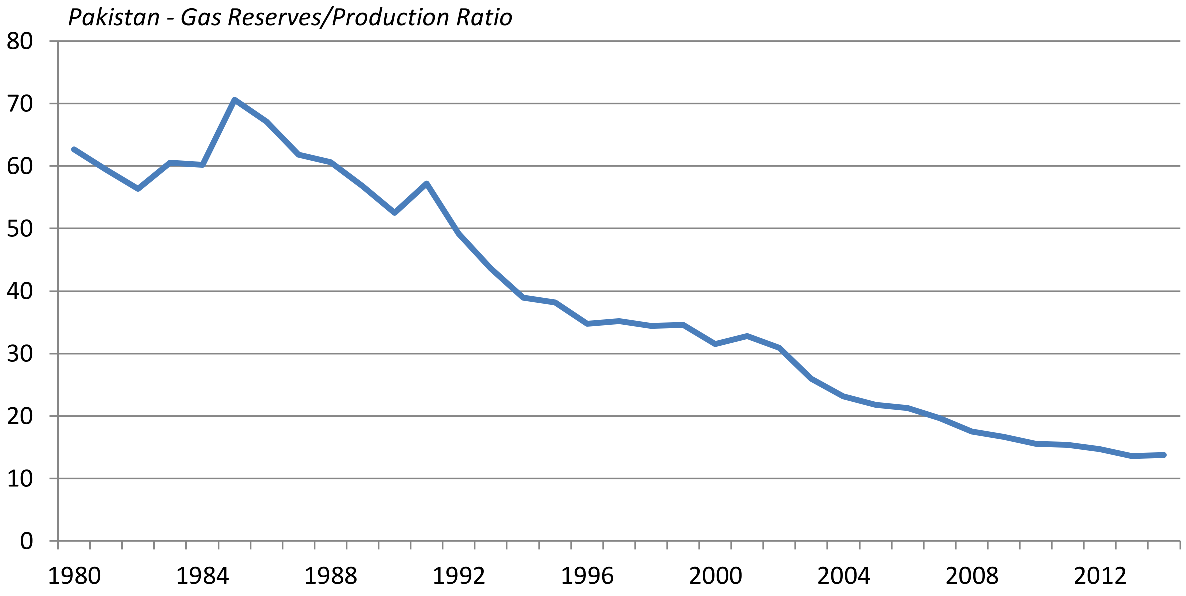
The Engro proposal which delivered the first Pakistani LNG terminal is based on a floating regasification scheme. In collaboration with Excelerate Energy, the Port Qasim LNG terminal is a 3.5 MTPA facility using Excelerate's Floating Storage and Regasification Unit (FSRU) named Exquisite which has been leased by Engro for the 15 year contract during which the 151,000 cm LNG capacity terminal will receive LNG and regasify it at about 400 mmcfd on a tolling basis. The throughput charge is $0.66/mmBtu in addition to a daily capacity charge. This capacity charge is effectively a Take-or-Pay arrangement which seeks to guarantee a cash flow for the asset owner, in the event that the capacity is not utilised by the LNG buyers. While this has created a potential risk free windfall in favour of the project sponsors, it has burdened the users with excessive costs and distorted the economics of fuel choices by essentially forcing the LNG use via this terminal.

There are other limitations / issues with this arrangement as well such as, not having an executable long term supply means the quantities arriving are on an adhoc basis, triggering capacity payments. Also, the FSRU has been performing the dual duty of bringing in LNG too when the design only required it to be permanently moored at the port. This also hampers the regasification and transfers while the ship is away. Also, the allocation and Third Party Access (TPA) provisions still need to be ironed out.

7.3.4 Issues and Challenges

Natural gas has remained and continues to be the dominant commercial fuel in Pakistan. Compared to the global average of about 24%, gas constitutes an enviable 51% of Pakistan's primary energy mix. While this is a real positive in an environmental sense as instead of relying on coal for its development, Pakistan has always opted for the much less carbon intensive and cleaner domestic fuel, the over reliance is now proving to be a challenge as mature fields struggle to maintain their production rates and new domestic supply is hard to come by.

The reserves to production ratio which notionally indicates the years of life worth of reserves left at current production rates was either steady or growing until the mid-80s but has been consistently falling ever since.



Source: BP Statistical Review of World Energy, June 2015

As producing fields continued to increase deliverability in the face of rising domestic demand, the reserves have continued their downward slide in the absence of any new major find that could replenish the depleted reserves. The situation is rather precarious now with current reserves to only last for another 14 years at their current rate of depletion.

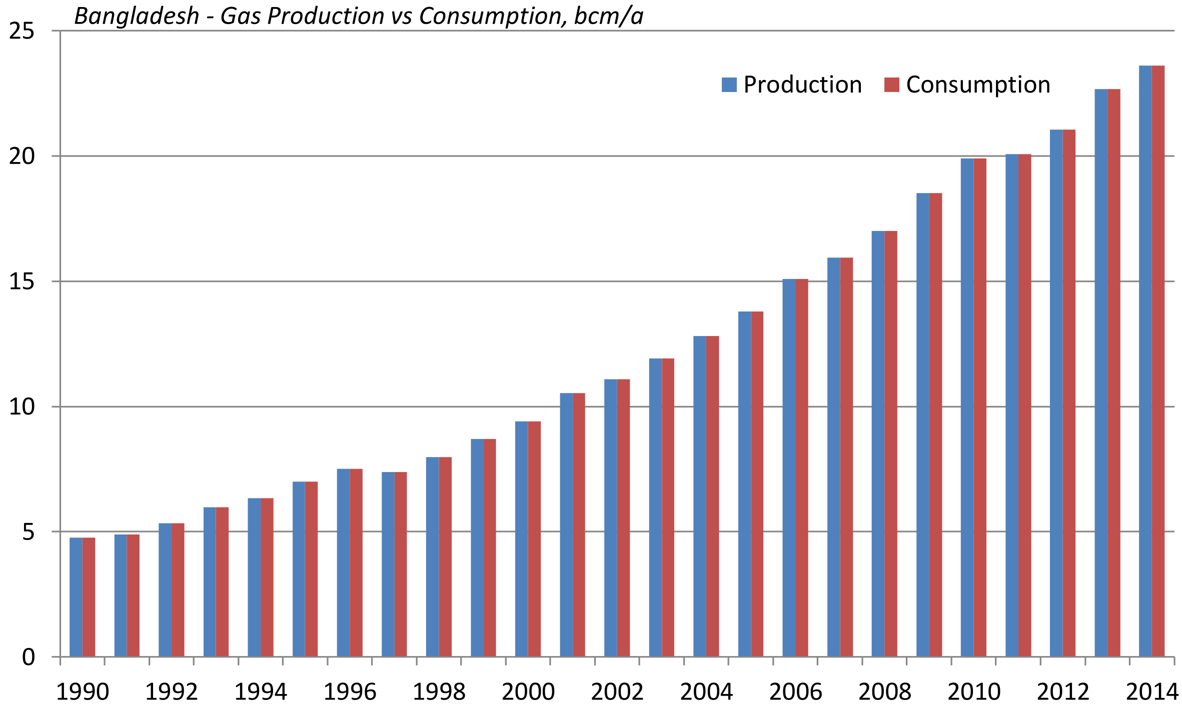
Successive petroleum policies have sought to promote domestic exploration and production but production has centred around low cost on-shore areas with little to no effort focused on high risk exploration areas. But perhaps the issue is not just about supply as it is also about demand. As a cheap and readily available energy, gas has found its way into areas which are not necessarily its traditional domain. The use of natural gas for transport or CNG has seen an astronomical growth with almost 3 million cars now converted. With domestic gas unable to cope with demand and more and more reliance on imported LNG at crude oil parity prices, the economics of continued CNG use does not seem favourable. Similarly, gas distribution has continued to be extended into regional areas with very low energy intensity such as domestic cooking alone without any heating load. Besides being commercially un-attractive, this has posed technical challenges such as mounting distribution losses and peak day demand management issues.

In the absence of a cost reflective market, the government is involved in setting the price for both upstream purchases as well as regulating gas charges to various streams of consumers including small residential customers. As price to each segment does not reflect the true cost of provision of the service, there is no pricing signal to control the consumption behaviour resulting in overuse and waste.

Apart from the pricing, the gas allocation priorities set by the government define who gets allocated according to their merit order. Under the gas allocation policy revised in 2013, the residential customers are allocated the top priority followed by power generation, industrials and CNG being the last.

7.4 Bangladesh

Bangladesh is another country with a large and established natural gas sector. From its early start with the commercial production starting at Sylhet gas field, the industry has grown to now account for more than 75% of the entire commercial energy mix, with oil largely providing the balance (20%) as coal carries a negligible share of just over 3%.



Source: BP Statistical Review of World Energy, June 2015

The chart illustrates the remarkable growth seen in gas production and consumption whereby both have quadrupled within the space of only 20 years. Majority of gas is consumed in the power sector which makes up more than 60% of the overall gas consumption. The demand could be higher, had it not been constrained in recent times due to restrained supply.

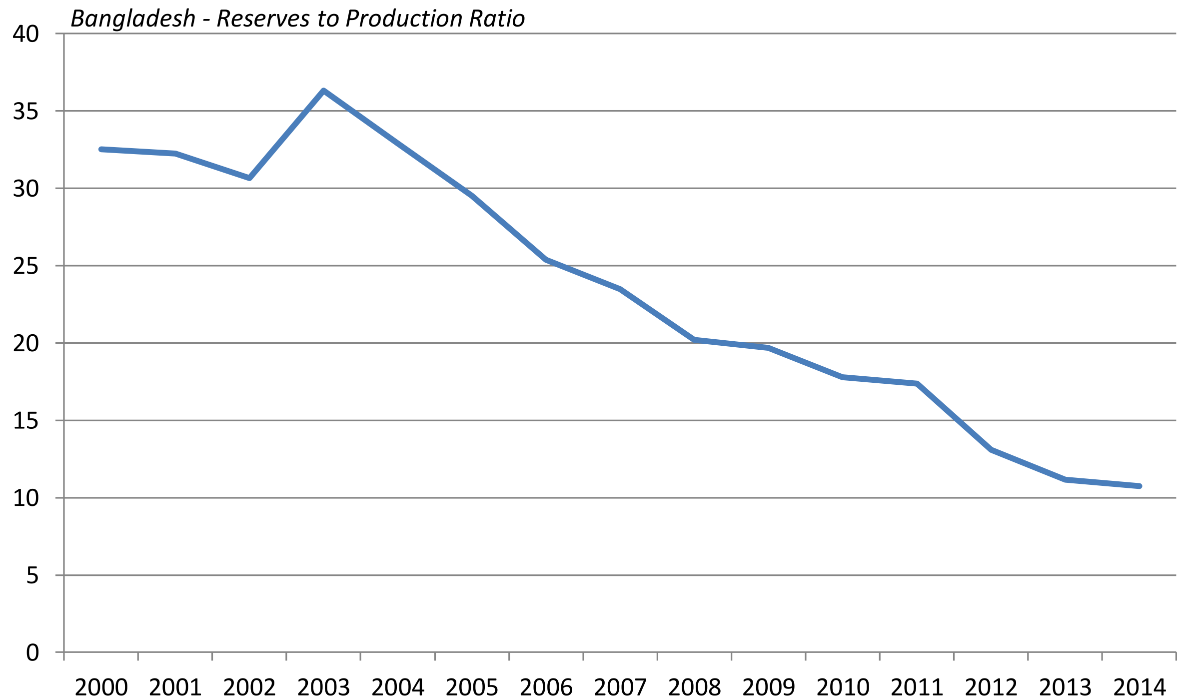
Government is directly involved in the energy sector through its entity Petrobangla which has separate streams looking after the upstream exploration and production, a gas transmission company to handle high pressure pipelines, 4 distribution companies operating in different franchise areas, a CNG development business besides some mining interests.

Private sector is also well represented in the upstream activities with international oil companies Santos, Chevron, Tullow and Niko Resources involved with more than half of Bangladesh's gas production. While Santos recently announced the permanent closure of the only off-shore Sangu gas field due to disappointing production rates, Chevron has continued a successful Exploration & Production (E&P) profile with expansion at its Bibiyana gas field allowing it to take a dominant role in domestic gas production.

Government is responsible for setting both the upstream gas prices as well as consumer prices. It enjoys the first right over any new gas production offered and the price is linked to fuel oil with a floor and a cap. While the producer can sell directly, any excess gas beyond government's needs, they can only do so domestically as no exports are allowed. Consumer prices are set by the government based on the type of consumer, regardless of the size or their location. Under the price revisions announced in October 2014, the consumer prices will be based on the upstream costs of the production instead of just looking at rate of return for the gas marketing companies. Average prices have stayed very low at around $1.90/mmBtu which fails to recover the cost of supply in majority of the cases.

The rapid demand growth has not been matched with a corresponding increase in domestic supply resulting in restrictions on gas use since the mid-2000s. The main impact has been on power generation where almost 25% of the gas fired generation capacity is stranded for either requiring a technical revamp or non-availability of adequate gas. In an unconstrained environment, this non-functional power generation demand along with unsatisfied I&C plus residential demand could add another 10 - 12 bcm annually to the gas demand. As costly and imported fuel oil is often used in power generation, the preference would be to convert these plants to also run on domestic natural gas subject to availability. This could potentially add another 3 to 4 bcm of gas demand.

There is a significant divergence in estimates for the recoverable gas reserves in Bangladesh. Petrobangla's own estimates put the remaining recoverable reserves at 0.4 bcm while the BP Energy Review puts them at 0.3 bcm. However a 2001 report by the US Geological Survey placed an estimate of 0.9 bcm on yet undiscovered reserves. The optimism unfortunately could not be supported by subsequent seismic surveys conducted and are not being considered for planning purpose any more.



Source: BP Statistical Review of World Energy, June 2015

The balance recoverable reserves have been consistently dropping from around 2000. At current rate of production, the remaining reserves have become alarmingly low and potentially could run out in about 10 years. Bangladesh is indeed facing a gas crisis and is in desperate need to find new sources to not only reduce the current supply gas but cater to the continuing growth in gas demand.

As the largest consumer of gas in Bangladesh, the power sector is the key driver for economic growth. The government estimates put the electricity demand growth at 140% of the GDP growth rate which means the unsatisfied demand for gas will continue to grow at the current rates well into the foreseeable future.

Even if it is assumed that the current production rates can be maintained with field depletion matched with additional deliverability, the projected demand shows the gap between supply and demand growing larger.

Bangladesh Gas Supply / Demand Projections

	2014	2020	2025	2030
Demand	23.60	35.69	45.89	61.19
Supply	23.60	23.60	23.60	23.60
Gap	(10)*	(12)	(22)	(38)

* ~ unmet demand

Source: Mahfuz / BIISS, 2011

The unrestrained projected demand could almost double by 2025 on the back of putting additional power generation using gas as well as converting the fuel oil/diesel based plants. Clearly this will need a substantial growth in supply which cannot simply be met with domestic measures to boost production but will need a large contribution from imported gas.

7.4.1 Gas Imports

The Myanmar-Bangladesh-India (MBI) gas pipeline project has been proposed for some time to connect the offshore production in Myanmar with markets in Bangladesh and India. Barring the technical challenge in laying such an interstate pipeline, the project showed potential as it gave Myanmar a ready market for its gas, while both Bangladesh and the eastern part of India would gain much needed gas from within the region.

Proposed Myanmar-Bangladesh-India Gas Pipeline

However, despite considerable time having been spent in discussing the modalities and project details, no real progress has been made so far. The tripartite nature of the arrangements with different priorities made it challenging to develop consensus on key issues. Different iterations were tried such as a direct route to India bypassing Bangladesh, similarly Bangladesh also considered a shortened route not extending into India but none of these could progress any further. Myanmar, meanwhile signed up a deal to transport its gas via a new energy corridor that also included crude oil pipeline into China. Bangladesh has also tested the idea of requesting an extension of the TAPI pipeline into its territory to receive the Turkmen gas. The transit fee across three countries with extra pipeline length involved means the economics of such an extension don't work out.

Bangladesh has also been looking at setting up an LNG terminal at Moheshkali Island near Cox's Bazar with a 90 km spur line from the terminal connecting into the transmission grid. In 2010 it invited Expression of Interest (EoI) from suitable parties on a 'Build-Own-Operate-Transfer (BOOT)' basis for a 5 bcma LNG terminal including port facilities on a 15 year licence term. After a few rounds of shortlisting and negotiations, the project is yet to take any shape.

Petro Bangla, who have been instructed by the government to expedite the project on a fast track basis, are now planning a floating terminal with about 500 mmcfd regasification capacity and berthing / mooring facilities to accommodate ships carrying between 138,000 – 260,000 cubic meters of LNG.

7.4.2 Issues and Challenges

Faced with more or less same type of challenges as its south Asian neighbours, the issues with regard to development of Bangladesh's gas sector are also quite similar. The over-reliance on gas as the cheap and once abundant fuel has now created a large wedge between limited and fast depleting domestic supply against burgeoning gas demand. The very low prices all around do not help the cause by not stirring enough investment in the upstream production and no pricing signals mean demand side in-efficiencies remain.

Access to technology is another critical one as better modelling / surveying techniques could improve production and optimisation techniques on the upstream side. Similarly, technology to revamp energy conversion, especially in power generation would unlock flexibility, efficiency and resource conservation.

The administrative and regulatory reforms should see a more dynamic energy sector with greater private sector participation. Promotion of competition through unbundling the supply chain and greater price transparency will definitely improve operational efficiencies.

Similar to Pakistan, coal has a very limited role in Bangladesh's energy mix. Total domestic coal reserves of about 2.7 billion tonnes do not see much action as total consumption including imports make up just 3% of the primary energy mix. Greater use in power generation, especially in one or two large scale base load plants can not only bring the weighted cost of power generation down but will also effectively deal with the chronic electricity shortages.

CHAPTER 08

8.1 Next Step – Energy Market Reforms

The impressive journey of gas exploitation and use in South Asia that started some fifty years ago has entered a new phase of growth and development. The gas group within SAARC comprising Bangladesh, India and Pakistan which could be ranked as the fifth largest in the world on the basis of its aggregate gas consumption, is facing a considerable challenge in the face of the stark gap between struggling domestic supply and the runaway demand. The governments in all three countries have recognised the issue and are overseeing their individual response to mitigate this shortfall. While the tactical response has been to identify new sources beyond their borders to formulate a supply response, the situation has added a new dimension in terms of international pricing of imported gas which these governments will find harder and harder to shield against, like they did with domestic gas. The budgetary deficits that allowed these governments to insulate the consumers from oil price volatility can now be compounded with imported gas prices without a cost recovery mechanism. Moreover, the enormous investments that will be needed to finance the energy infrastructure to support the growing demand cannot just be borne by the governments alone and the private sector will need to be convinced of their commercial viability before committing these large funds.

There is therefore an urgent need to structurally transform the gas industry by way of embracing competition reforms just like how gas markets have evolved in other regions and are now enjoying efficient and robust markets. These markets are able to accurately allocate the cost to cause and generate pricing signals to control supply and demand response besides identifying investment needs for infrastructure augmentation.

The challenge to introduce competition reforms within the energy sector can be classified under four streams: -

Structural Reform: This would involve complete separation between potentially competitive functions within the energy industry from monopolistic infrastructure services. Also, facilitating a competitive environment for offering and utilisation of commercial services

Competitive Neutrality: Establishing corporatised governance structure for major government businesses and treated at par with the private sector businesses

Access to Monopoly Infrastructure: Ensuring non-discriminatory and transparent access to monopoly infrastructure and get independent authority to oversee charges for these monopoly services

Market Establishment: Set up markets to transparently determine prices for energy commodities by laying down uniform rules and procedures and manage their day to day operation

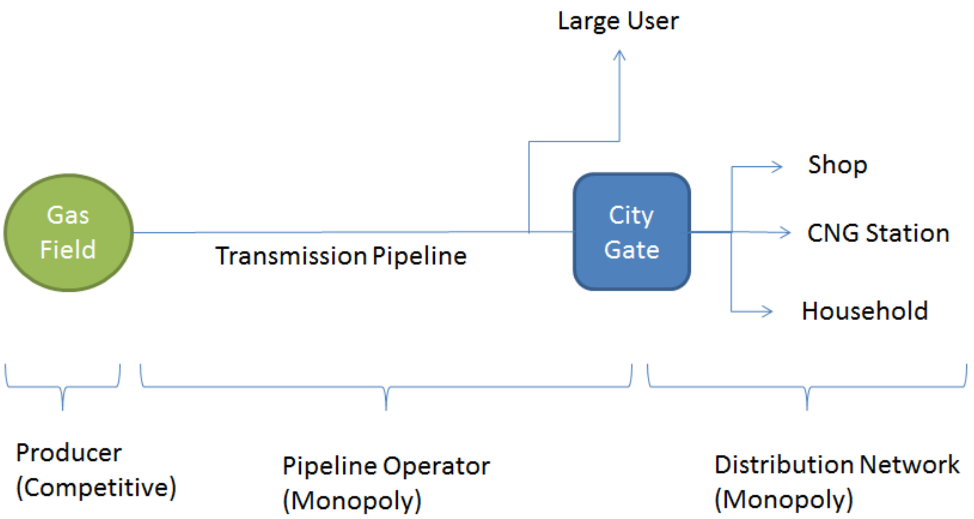
8.2 Structural Reforms

The old structure of the now liberalised markets in countries like the UK, USA and Australia was very similar to the current state of play in South Asia with vertically integrated monopolies and no competition, offering bundled services and embedded cross subsidies between market segments. The energy sector reforms enabled greater competition and deregulation, allowing remarkable growth and efficient operation of the traded markets. It has allowing delivered cost of energy to drop overtime, as well as enhancing supply security and availability, by generating timely pricing signals for network augmentation.

The gas chain linking the gas produced to the consumer fundamentally involves three stages. The first one is the field where gas is produced; the second one is the high pressure pipe that then moves these gas molecules to various offtakes along its path and the last one is the distribution network that receives these molecules via the city gate transfer point and delivers them to the consumer connected via its low pressure gas grid.

The typical integrated model currently applicable in South Asia involves the gas utility performing all the functions downstream of the gas field which means holding onto the monopoly assets such as pipes and networks thereby limiting access to others who can compete for service based on lower price. Some degree of notional Third Party Access (TPA) is now available in India and Pakistan but in practice it is hard to imagine how it can be executed with current utilities continuing to perform their dual role by owning the monopoly assets.

Simplified Gas Chain



Before: -
Producer →Gas Utility →Large User; Shop; CNG Station; Household

After: -
Producer →Shipper 1; Shipper2; Shipper3 etc.
Shipper1 →Pipeline Operator →Network Operator →Shop
Shipper2 →Pipeline Operator →Network Operator →CNG Station
Shipper3 →Pipeline Operator →Large User; Network Operator →Household

If we look at the schematic above, both the transmission and distribution of gas are monopoly activities which are currently owned by the integrated utility and are bundled with the overall retailing activities carried by them. As a first step to unlock competition and improve operational efficiency, these services will need to be un-bundled. The gas transmission activity needs to be dis-entangled and operated at an arm's length with the eventual aim of flogging it as a separate business. Similarly, the low pressure distribution networks need to be carved out, ideally as multiple franchises handling gas distribution based on geography. This will allow monopoly assets to operate independently while the multiple energy retailers will all have a level playing field without any preferential access or position. With several players offering similar products and services, the competition between themselves should see the prices come down, benefitting the consumers.

To implement these changes, the new gas supply chain would involve multiple buyers of gas contracting directly with the gas producers. In fact the producers themselves can also move their gas into markets for onwards sales to consumer. The buyer of gas will then haul its gas as a shipper using the pipeline which is now owned by an independent operator offering its services on a non-discriminatory basis and as per published tariff, using a queuing policy that spells out how finite capacity will be allocated on the pipeline. The shipper will then receive the gas at the destination network receipt point and using the services of the network operator, nominate the gas to be delivered to the consumer's premises.

8.3 Competitive Neutrality

One of the major hurdles in promoting fair competition in the gas business is the current domination of the sector by government owned enterprises that also own and operate the monopoly assets. The question that dominates in private sector entrepreneurs' mind is whether they will be able to enjoy a level playing field if they were to set up a new enterprise in competition with the already dominant government entity. The legacy arrangements in existence may continue to provide them with a competitive advantage against the new starts and therefore create a barrier to entry. Similarly, allowing government entities to gain access to future policy settings or plans as a result of the existing reporting line or management linkages may allow them to gain clear headway against their private sector competitors.

To implement competitive neutrality, therefore, a thorough review of the current functioning of the operational segments will be required where competition is to be fostered, such as gas retailing. What this will entail is to ensure government owned retailer does not have any special access to carrying out its tasks which may not be available for any other entity. Things such as demand projections that are in use by the government entity must also be provided to the new entrants. Another example could be the historical consumer data which is available to the incumbent public utility, should also be made public so that commercial decisions are made by new entrants that are consistent with historical knowledge.

8.4 Access to Monopoly Infrastructure

Some progress has been made in India and Pakistan with regard to setting up a mechanism for Third Party Access (TPA) for gas transportation, especially to accommodate the imported LNG to move through the system and allow delivery to the buyer. While encouraging as a first step, there needs to be a whole lot of effort required to establish a system wide transparent system involving gas receipts domestically and imported via LNG terminals. It should also include the connected high pressure pipelines, gas haulage through the grid and its delivery at its destination in a non-preferential and transparent manner.

In order to successfully implement a fully transparent and non-preferential access, the open access regime should satisfy the three conditions; the coverage should include all the monopoly assets along the supply chain; it must be handled by a dedicated system operator and finally, the access must be overseen by an independent regulator.

As there is no system wide process currently in place, the piece meal approach to access involving some but not all the supply chain elements cannot satisfy the requirement of an open access environment. Furthermore, the continuing ownership of the assets by the same commercial entities who are selling gas along with the third parties requiring access through their terminal / pipeline etc. creates an uneven field and a conflict of interest hurdle.

The issue of capacity available, its parameters and tariffs etc. need to be widely available. If any new capacity is to be made available, it should be properly broadcast so the allocation is done in a fair and transparent manner. If the shippers are looking to express their interest in future capacity expansion projects, there should be a queuing policy that describes how these will be treated so the new capacity is allotted on a first come first served basis.

The regulator will have to take a very direct role in determining the allowable tariffs for the haulage services offered by the pipeline. The standard procedures to determine the value of these monopoly assets such as Depreciated Optimised Replacement Cost (DORC) should yield an acceptable rate of return, translating into various tariffs that are charged for these services along with some incentives built in for improved efficiency and reduction in costs to enhance their profitability and help lower the cost of delivered energy to the consumer.

8.5 Market Establishment

The gas industry in South Asia has matured to the extent that it needs genuine pricing signals to operate the supply and demand balance. The arrival of LNG into the mix has perhaps hastened the need to see some form of a notional market where bids and offers by buyers and sellers are prioritised based on prices. The establishment of a market will not only facilitate gas on gas competition but will also allow gas to be consumed according to the intrinsic value it commands in each market segment.

The Transmission System Operator (TSO) as well as a Gas Market Operator (GMO) are the two new essential roles to enable a gas market to operate. They do not have to be separate entities and in fact would be easier if one operator is dealing with both pipeline system as well as the market operation. The TSO function would involve a centralised control of the physical running of the pipeline grid. Regardless of the ownerships of each and every asset, the TSO would direct and monitor the day to day functioning of the network to ensure the supplies are matched against the demand. The daily balancing may at times require it to either require more injections to be sourced into the grid or restrict the deliveries in order to maintain system balance. The TSO can also have access to storage which it can directly feed in at times of higher demand as a balancer of last resort. This will ensure a centralised management of daily gas balancing and facilitate security of supply in a coordinated manner.

The GMO role on the other hand would look at the commercial operation of the market to determine and flag the daily price of gas as well as share vital information via Bulletin Board etc. for the market participants to make commercially well informed decisions. This daily balancing and spot clearing market will work by organising all the offers for gas supply in ascending order based on price and the cumulative supply that satisfies the aggregate demand is scheduled and the marginal supply offer sets the price as shown in example below with 180 TJ demand gets scheduled @ $3.50/GJ: -

Daily bids/offers Stack determining Market Price

Supply Offer	Price	Cumulative	Demand Bid	Market Price
100 TJ	$ 2.00	100 TJ		
50	$ 3.00	150		
40	$ 3.50	190	180 TJ	$ 3.50
10	$ 6.00	200		

In the SAARC region, India has now established a fully functional domestic LNG import industry while Pakistan recently launched its first LNG terminal and Bangladesh looks set to follow suit, it makes whole lot worthwhile for these neighbouring countries to share their experience and assist each other in their own quest to establish their individual capabilities. The cooperation can be offered in a number of ways and in a variety of areas such as capacity building via industry linkages, sharing of infrastructure or even accommodating regional requirements via flexible contracts and other commercial instruments. A few ideas to perhaps facilitate a regional discussion for LNG cooperation could include the following: -

8.6 LNG Group Buying

The idea of group buying or forming a buyer's cartel for LNG has been proposed some time ago between India and Japan with other countries invited to join in. In principle, this would allow the group to exert more influence in their negotiations with the sellers to get better price and other contractual terms by using the group's combined LNG sales volumes as a bargaining chip. The concept is not new as the oil and gas producers often pool their joint venture marketing resources together to negotiate sales collectively, eliminating the competitive pressure of individual deals. The idea has even been tried by the gas exporting countries themselves through the Gas Exporting Countries Forum which, however, mainly deals with export related issues rather than collective marketing etc.

The concept will be particularly useful in the South Asian context as countries are at different stages of developing their LNG market know how and competencies. Group negotiation will allow both Pakistan and Bangladesh to harmonise their individual contract terms and offer them sufficient clout while negotiating with India who has already developed sufficient experience in structuring LNG deals.

8.7 SAARC LNG Aggregator

There is potentially a role for regional LNG aggregator that can extend its operational coverage to the SAARC neighbouring countries by managing the LNG supply and demand balance for the entire region. Petronet India for example can perform this role where its contract portfolio is extended to also include LNG demand for both Pakistan and Bangladesh who can benefit from Petronet's experience and not having to deal with credit worthiness issues. Similarly, Petronet will enjoy greater flexibility and diversity in its portfolio, allowing it to structure better deals and lower the cost of procurement for the entire region.

8.8 Contractual Flexibility

Contract flex is another area that can be used to promote LNG cooperation in the SAARC region. Indian firms with flexible LNG contracts, especially ones allowing destination change can re-route certain volumes to neighbouring countries to fulfil their needs without having to organise individual long running contracts on their own.

While destination clauses used to be fairly rigid and did not usually allow this, understandably many new contracts such as the ones signed by India do carry this provision and can therefore be part allocated to meet regional needs of the neighbouring countries. It can also be beneficial for India in that the Take-or-Pay risk with contract volumes can be lowered or even wiped off, depending on the disposed volumes.

8.9 LNG Swaps

The LNG cooperation can also be extended by structuring physical swaps whereby LNG is received by India, having the physical and commercial infrastructure to do so and then return the equivalent amount of regasified LNG via pipeline to the neighbouring countries. The advantage with such an arrangement is that the swap counterparties do not have to have LNG infrastructure to structure such a deal but they will need physical interconnectivity through a regional gas grid. For this to play out, cross border connection with gas pipelines between India and its neighbours will be required. Perhaps a techno economic evaluation can be undertaken to see if it is cheaper to organise a swap with the cost of haulage through interconnection vs cost of building domestic LNG import facility and paying investment charges.

8.10 LNG Tolling

Another possibility is for the regional countries to organise some sort of a tolling arrangement with Indian gas fired generation units whereby LNG bought by them is delivered to the power plant in exchange for getting access to generated electricity off the Indian grid using agreed heat rate conversion etc. Again, for this to work out, interconnection of electricity grid is essential. The beauty with this arrangement is that it does not have to be restricted to gas consuming neighbours only. Even Bhutan and Nepal can gain access to LNG sourced electricity via such a tolling arrangement.

CHAPTER 09

9.1 Regional LNG Import Terminals

Under the Terms of Reference of this study, a specific item to be considered was the possibility of setting up joint LNG import terminal(s) within the SAARC region to cater to the regional gas demand and to see how they stack up in terms of costs for power generation and industrial use against alternative fuels and individual terminals.

SAARC countries with gas demand including Bangladesh, India and Pakistan, all have pursued or are in the process of establishing LNG import capability of their own. This comparison can therefore highlight whether it is cost effective to promote infrastructure development individually or collectively through some sort of a sharing mechanism. The energy demand especially gas demand growth that is continuing in the region gives a clear impetus to the facility expansion and the certainty of knowing that such an expansion will be well utilised.

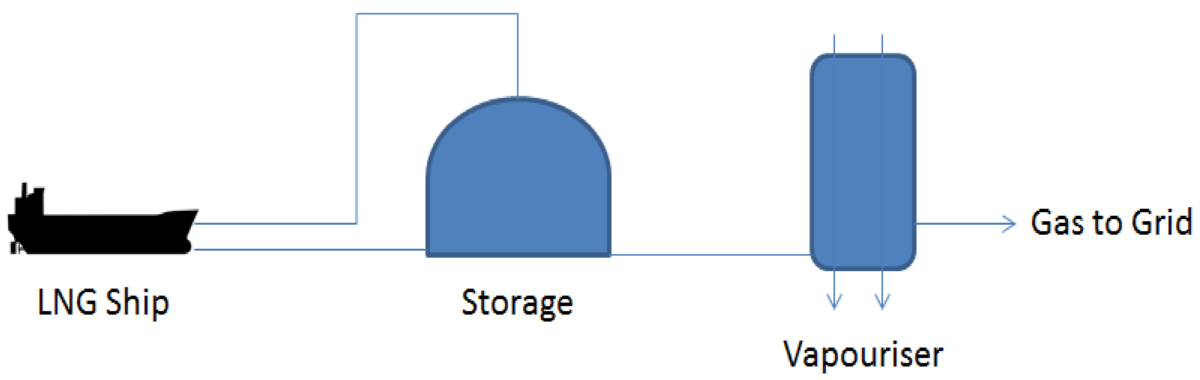
The LNG receiving and regasifying terminals are perhaps the lowest cost and simplest component of the supply chain. Their job is to be able to receive LNG in liquefied form from the LNG ship (if onshore) and store them at a storage facility. The facility is then able to discharge regasified natural gas at a certain rate in to the local gas grid by vaporising LNG through a heat transfer process and maintain the balance LNG in the storage as a buffer between further LNG receipts and vaporised natural gas send outs.

The LNG import terminal can broadly comprise the following components: -

LNG receiving and unloading facilities

These primarily include the port facilities to be able to transfer the LNG received into the storage tanks. As ships vary in size and capacity, the facilities should be able to accommodate a range of LNG flows, especially if capabilities to unload very large vessels such as the QMax are also required. Usually the LNG is flown to the onshore storage via pumps located in the ship cargo tanks.

Simple schematic of an onshore LNG terminal



While the loading line(s) are receiving LNG into the storage, the vapours inside the tank are displaced and are returned to the ship via the vapour return line to maintain a positive pressure in the ship.

9.2 Storage Tanks

Ideally two or more storage tanks are required for on-shore storage to maintain sufficient buffer as well as allow redundancy in the event that one or more tanks are offline. Costs however dictate that a single but larger tank is deployed which can simultaneously receive LNG from the ship as well as discharge LNG for gas injections into the grid. The key is to maintain structural strength and insulation as LNG is stored at -162deg C in liquid form and 1/600th of its gaseous volume. The structure can be single, double or fully contained depending upon what and how many containment layers of walls are present which impact on the capital and operating costs as well as land requirement and safe distance to jetty etc.

9.3 Vapour Handling System

The stored LNG continues to produce Boil off Gas (BoG) through vaporisation due to heat transfer between super chilled liquid in the tanks and the ambient air. The vapour handling system allows channelling these vapours in an optimum manner to avoid unnecessary re-processing and minimise waste. During ship unloading, the vapours produced can be returned to the ship however excess boil off gas can either be recondensed or be injected into the grid. In the event that none of these options are available, gas can be flared or vented to atmosphere in emergencies.

9.4 LNG Vaporisers

This part of the terminal is responsible for conversion of LNG into gaseous form so it can be injected as natural gas into the distribution system. It is essentially a heat exchanger which can either draw heat using sea water or via part combustion of the send out gas and use it to change the cold LNG to natural gas which is close to ambient temperature. Open Rack Vaporiser (ORV) uses LNG flowing through the tubes while seawater falls over them for the heat exchange to take place. The Submerged Combustion Vaporiser (SCV) utilise hot gases from the products of gas consumption to heat a water bath which transfers the heat to LNG for vaporisation. The ORV are generally costlier to build while SCV have a much higher operating cost as some gas is consumed as fuel.

9.5 Joint LNG Terminal Location

Both India and Pakistan have infrastructure and ancillary facilities to support LNG imports. Bangladesh on the other hand, has carried out background work and planning to install its first LNG terminal near Chittagong. All three states can therefore be chosen to deploy the joint terminal as the existing facilities or the sheer necessity can be used as the basis for this investment decision. It may however be worthwhile to quickly run through the key factors usually considered for this purpose before finalising the recommended location.

9.5.1 Port Facilities

One of the foremost criteria for site selection would be to see if the port can be flexible enough to handle the wide variety of LNG ships currently deployed. Of particular importance is to see if the port can receive the Qmax carriers with more than 266,000 cm of LNG at a time, requiring substantial draft as well as easy manoeuvrability. The approach to the harbour and the overall layout of marine berths are both quite significant factors in determining the ease with which an LNG tanker can reach its berth safely. If geography can allow the location along a straight and low wind channel, that can really help in deciding the location of such a terminal. Due to the substantial draft such large ships require, the channel depth is another factor to be considered. In cases where the depth is less than 15 meters, extra dredging at additional cost will be required adding to the project expenses. Also, if dredging is carried out the soil contamination as well as silt prevention will be needed for the site.

9.5.2 Source and Availability of LNG

Although the location of an LNG terminal does not on its own guarantee a source and availability of LNG, it is important to ensure the site is located along the major LNG transit ways so that facilitation of trades can easily occur. Ports in both Pakistan as well as Indian west coast are well located to be approached by LNG ships from Qatar plying on the busy route to large LNG markets in the Far East. The relatively short distance to the Middle East means that not only the shipping costs will be lower but also that a variety of ships can undertake this journey without needing special capabilities required to undertake longer journeys. Similarly, the port in Bangladesh can boast of its relative proximity to the fastest growing and soon to be the largest LNG exporter, Australia. This can also assist in propagating LNG based gas supply into Bangladesh as well as potentially the eastern parts of India.

9.5.3 Shipping Arrangements and Relevant Transport Economics

LNG can either be bought without shipping (FOB) or on a delivered (DES) basis. As South Asia is a relatively new LNG market, most of the existing arrangements have involved delivery of the LNG included by the seller who generally owns their own shipping fleet to allow flexibility of sales on both short and long term basis. This situation will change in future as LNG industry matures and the local aggregators will want to exploit the arbitrage between regions and get a better deal such as the recent deal by India to buy gas at Henry Hub and organise liquefaction and shipping individually. For the purpose of our analysis we can assume the LNG will be on a delivered basis as during the launch and ramp up phase, it may not be preferential to tie up capital resources for long term ship chartering. We can however analyse the structure of the shipping costs to determine indicative haulage costs for LNG purchases for the Joint Terminal.

The shipping costs are made up of three items. The cost of chartering the ship is the foremost and basically reflects the cost of leasing the ship on a short/medium or long term basis. The short term chartering involves round trip duration for LNG haulage while long term charter spans over many years. With the build-up in spot trading and number of speculators increasing to capitalise on market movements, the short term chartering is growing in popularity whereas earlier arrangements typically involved long term charters accompanying a multi-year LNG sales contract. As a general rule, long term charter rates tend to be stable while short term rates can show volatility depending upon the supply / demand situation. With the increase in LNG ships and short term trades though, the charter rates continue to follow a downward trend and the gap is closing with long term charters. Along with the drop in LNG prices, the charter rates have also dropped by almost half from around $100,000/day to around $60,000/day for the newer fuel efficient DFDE ships.

The next component is fuel cost as well as boil-off losses that occur during the LNG voyage. The fuel cost represents the amount of fuel required by the ship engines to travel as well as maintain ancillary services on board. The boil-off is the LNG that is vaporised during the journey and represents the shrinkage or losses in LNG cargo. Both the fuel and boil-off rates depend on the length of journey as well as ship size, the amount of cargo and the nautical speed / distance. The final component is the port costs and other direct / indirect imposts in relation to the shipping arrangement.

We can roughly estimate the shipping costs for LNG delivery to a South Asian port by using assumptions for the size of the cargo and prevailing charter / fuel oil rates from industry surveys such as IGU World LNG Report etc. as follows: -

Load = 150,000m^3

Distance = 1,600 nautical miles to Indian port from Qatar
Speed = 14 knots
Fuel Oil Usage = 160 tonnes/day @ $500/mt
Charter Rate = $80,000/day

1. Charter Cost = 80,000 x (5 x 2 +1) = $880,000
2. Fuel Cost = 160 x 5 x 2 x 500 = $800,000 + 250m^3 LNGBO (~$50,000)
3. Port / Other Costs = $0.22/mmBtu

Total = $0.70/mmBtu

Based on the above assumptions, the shipping rates to South Asia from Qatar look attractive and indicate a higher netback compared to deliveries into Europe and therefore create an arbitrage opportunity for the region's LNG demand growth.

9.5.4 Ease of Connection to Pipeline Network

Another important factor in determining the location of an LNG import terminal is its proximity to a suitable entry point into the domestic high pressure gas transmission system. All the prospective ports in South Asia offer this functionality with both India and Pakistan having existing tie-ups available for the operating terminals in each country. Based on the criteria above and allowing for the better access for regional countries, India is considered as the location to establish the joint LNG terminal for evaluation purpose.

9.6 Joint LNG Terminal Cost Analysis

With India selected as the location to base the notional project due to ease of access and better connectivity potential with other countries within the SAARC group, we can now get on with the task of estimating indicative costs to set up such a facility.

There are two options for setting up the LNG import terminal. It can either be a floating type (FSRU) or on-shore with land based LNG storage and regasification. The FSRU would definitely be much cheaper and quick to set up but given the need to support regional LNG security with adequate storage capabilities to meet a wider range of flows in and out of the facility, an on-shore terminal is preferred.

As a joint terminal being used for interstate gas demand, the size of the buffer and deliverability is important. The design of the plant should also be capable of further expansion if and when new capacity is required to be added. The initial capacity is proposed to be 6 MTPA throughput with two LNG storage tanks and a combined storage capacity of 380,000m^3. The jetty and berthing capabilities would allow Qmax ships to be unloaded besides the normal LNG carriers. The summary of the design criteria and the estimated costs are as follows: -

- LNG Terminal Annual Capacity = 6 MTPA (8bcm/a)
- LNG Storage = 380,000m^3 (2 x 190,000)
- Daily Regasification Capacity = 22 mmscmd
- Vaporisation Mode = Open Rack (ORV)
- Estimated Cost = $770 million

The terminal will offer regasification services on a regional basis while boosting the security of supply issue which is of vital importance to all the benefiting countries. The project however is expected to be financially viable and to operate on a commercially sound basis. In order to determine the financial attractiveness of the project, a Discounted Cash Flow (DCF) analysis is carried out using assumption for the set up and operation of the facility.

The input parameters used to determine the project NPV and IRR are: -

Input Parameters for Financial Analysis

Capital Cost	$ 770 million
Plant Capacity	6 MTPA
Utilisation	80%
Regas Throughput	256,224,000 mmBtu
Variable Cost	1% of Processed Gas
Natural Gas	$9.0 per mmBtu
LNG	$8.4 per mmBtu
Price Increase	0.96%
Staff Wage	$ 80,000
Tax	30%
Discount Rate	10%

For the purpose of the analysis a capacity utilisation rate of 80% is used, signifying the likelihood that the plant will be well utilised by the participating countries. It is also assumed that the plant will charge a flat regasification rate of $0.60/mmBtu which would mean the LNG bought at, say $8.4/mmBtu ($7.7/mmBtu FOB + $0.7/mmBtu Freight) will be injected into the grid at a price of $9.0/mmBtu. It is also assumed that the charges will escalate by about 0.96% annually.

Running the financial model for the expected 40 years life of the project and using the notional 10% interest / discount rate yields a healthy Net Present Value (NPV) of $204 million and an IRR of 12.9%

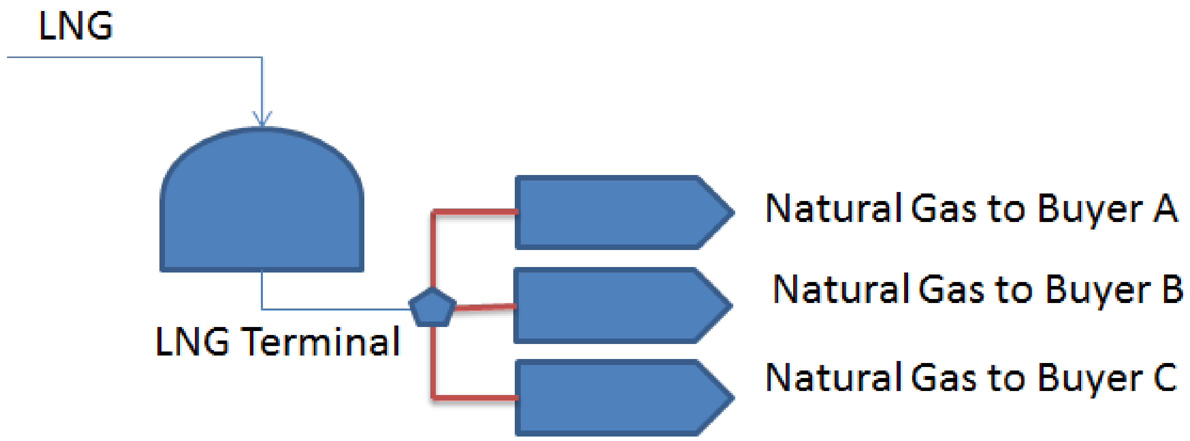
Results	
NPV	$204 million
Project IRR	12.9%

The financial modelling results indicate that based on assumed parameters, the LNG terminal will be adequately profitable and a sound investment decision.

9.7 Project Ownership and Structure

As the project would be a joint effort between the South Asian countries, an independent company part owned by the constituent SAARC countries with equal share may be established. The proposed new company, South Asian LNG Terminal Operator (SALTO) will be the owner / operator of the LNG terminal and will allocate its capacity to the JV partner countries based on their share of the investment.

SALTO will not only manage the operation and maintenance of the LNG terminal, it will also look after the regasified LNG access into the gas grid and its ultimate delivery to its nominated destination.



To organise end to end access, SALTO would have to establish linkages across domestic gas grid to be able to deliver into neighbouring countries from India where the proposed terminal would be located. In the case of both Pakistan and Bangladesh, therefore, this will mean interconnect pipelines stretching beyond the western and eastern parts of the Indian grid into the domestic networks of the other two countries. This will allow full access to the terminal for both Pakistan and Bangladesh as gas will be managed by SALTO from the time it is delivered by LNG carrier to its delivery into the national transmission system.

9.8 Cost Comparison – LNG vs Other Fuels for Power Generation

With the cost of regasification estimated to run the LNG terminal profitably, we can compare how the fuel (RLNG) stacks up against the alternative fuels. Apart from exclusive areas where gas is the only choice such as fertiliser industry, the industrial uses including power generation are generally indifferent to the choice of fuel and are largely driven by the economics. Things have to some extent changed in markets that have started to apply a price on carbon as low emission characteristics of gas then builds a commercial case for it. In South Asia though, the case for gas would have to be based on economics with environmental benefits complementing the choice.

A simple comparison between gas and comparable fuels can be made by considering the Short Run Marginal Cost (SRMC) for power generation. If it is assumed that the generator is fully capable of running any fuel and the logistics as well as other operating costs are identical regardless of the fuel chosen, the decision to pick any fuel can simply be made on the basis of its cost per unit heat content only. The comparison between natural gas from the LNG terminal is compared with diesel and fuel oil by using a tonne of oil equivalent each, representing same amount of energy to see how the unit cost of generation stacks up for each. Some adjustment is made for the lesser burning efficiency of distillate and fuel oil against the cleaner burning gas.

Estimated Unit Cost of Power Generation

Item	Unit	Natural Gas	Distillate	Fuel Oil
Fuel Cost	$/Tonne	--	450.00	370.00
	$/mmBtu	9.00	11.17	9.41
Comparative Cost	$/ToE	360.00	448.67	360.26
Generation Cost	$/MWhr	81.82	106.83	92.37
Unit Cost	$/kWhr	**0.08**	**0.11**	**0.09**

The table above highlights that based on spot rates for LNG and using estimated shipping and regasification calculated above, the injected gas into the domestic market at $9/mmBtu will compare favourably against both fuel oil as well as distillate, barring operational and conversion / handling costs etc.

9.9 Cross Border Delivered Prices

There is no existing cross border connectivity of individual gas grids in South Asia. This means that while they can finance and establish a joint terminal to import LNG, the regasified LNG cannot physically be sent out across from India into either Pakistan or Bangladesh. In order for such a transfer to take effect, spur lines from India will need to be built, travelling across the border and forming a new receipt point into the domestic transmission system. Even if the interconnections are rolled in and managed by the Joint Terminal as part of its service to deliver RLNG to Pakistan and Bangladesh, the gas will need to travel along Indian transmission system before it reaches the entry into the interconnect. This means there will be haulage charges associated with use of Indian grid as well as transportation tariff for the newly built interconnections.

Detailed costing and design of such a link is beyond the scope of this study but we can roughly estimate the cost of haulage to Pakistan as $1.5/mmBtu for Indian network tariff plus an additional $0.5/mmBtu for the extension and ancillary services while the same for Bangladesh is estimated as $2.0/mmBtu plus $0.6/mmBtu. The total delivered price of RLNG into each country associated with the Joint Terminal can therefore be itemised as follows: -

Estimated Price of RLNG ($/mmBtu)

	India	Pakistan	Bangladesh	Comment
LNG Price (FOB)	7.70	7.70	7.70	JCC @$53/bbl
Shipping	0.70	0.70	0.70	
Regasification	0.60	0.60	0.60	
Indian Tariff	--	1.50	2.00	
Interconnect Charge	--	0.50	0.60	
RLNG Delivered, Joint Terminal	**9.00**	**11.00**	**11.60**	

9.10 Joint vs. Dedicated LNG Terminals

With the indicative price now determined for RLNG based on Joint Terminal located in one SAARC member country, we can do a cost comparison now to see if it is cheaper against the dedicated local terminals. To do this, we can take the example of Pakistan where a terminal is operating to see if the RLNG price via Joint Terminal works out any better than the dedicated Port Qasim local terminal.

RLNG Price -Dedicated vs. Joint $/mmBtu

	Dedicated	Joint
LNG Price (FOB)	7.70	7.70
Shipping	0.68	0.70
Regasification	0.66	0.60
Indian Haulage Tariff	--	1.50
Interconnect Charge	--	0.50
Other Charges	0.60	--
RLNG Delivered Price	9.64	11.00

Keeping the FOB price of LNG bought the same, the shipping needs to take into account the change of destination however because Port Qasim is along the same route but only closer, the shipping is considered as $0.68/mmBtu. Similarly, the regasification is based on the existing LNG terminal's charge which is $0.66/mmBtu. While the dedicated LNG terminal in Pakistan does not have to pay the haulage for either the Indian Gas grid or the interconnect fee, there will still be a service charge for moving RLNG through the Pakistani grid. It is assumed as $0.60/mmBtu. On the basis of these assumptions, the overall cost of RLNG in the case of Pakistan via a dedicated terminal against the joint terminal in neighbouring country clearly indicates a preference for a dedicated local terminal as opposed to a joint terminal. The reason is obviously the extra haulage involved in moving regasified LNG over longer distance as opposed to localised regasification. This is further compounded by the fact that the domestic gas grids are not already connected and to facilitate such a joint project, the connectivity first needs to be established at extra cost.

CHAPTER 10

10.1 Conclusions and Recommendations

The rapidly growing countries in South Asia are facing major energy imbalances as local demand far outstrips supplies. Domestic Gas has helped some of them overcome this energy shortfall but overreliance and lack of pricing dynamics has resulted in faster depletion which can only be addressed via imports. Domestic institutional capabilities need to be streamlined as well as introduction of regulatory reforms to allow gas market to run efficiently and transparently.

South Asian countries can benefit a lot by working together and sharing their experiences and abilities at a regional level. Exploring one area of such a cooperation being the setting up of joint LNG import terminal highlights that while the project would be viable as a commercial venture, it will not allow efficiency of logistics and price advantage for other participating countries, apart from the host where the terminal is located.

While physical setup of shared facilities may not be feasible for the region as a whole, they can still explore cooperation in other areas such as promoting technical knowhow via training and development, exploring commercial linkages such as group buying or offering contractual capacities on a regional basis etc.

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