Natural Gas in Pakistan and Bangladesh: current issues and trends

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Preface

Natural Gas commentary and industry focus on South Asia tends to target India, the largest gas market. Pakistan and Bangladesh in aggregate however equal India in terms of gas consumption and as such are significant markets in their own right. Pakistan's gas consumption is almost the same as France's while Bangladesh consumes 30% more gas than Poland. Both countries have their own domestic upstream gas industry but both suffer from the problem of low regulated domestic market gas prices creating a disincentive for exploration of new indigenous supplies, primarily as a consequence of the global upstream cost inflation of the mid-2000s.

This paper by Ieda Gomes is an in-depth study of the genesis and present situation of these two significant gas consuming countries, including the drag on their potential economic output as a consequence of gas supply shortages and the attempts of each to secure gas import projects be they pipeline gas or LNG. Their lack of success to date due to lack of institutional capability, sufficient trust with potential suppliers or merely procedural shortcomings is recounted. This said, there is clearly a need for both a re-invigorated upstream domestic exploration and development campaign and the implementation of a coherent import strategy. Reform of domestic pricing is critical to the achievement of both these necessary developments.

This paper is a detailed and comprehensive study of gas markets at a crucial stage of their evolution and as such will be of interest to both academic researchers and to commercial organisations interested in participating in their future development.

Howard Rogers, June 2013

Introduction

Natural gas plays a major role in the energy matrix of Bangladesh and Pakistan. In 2011 the combined gas consumption in the two countries was nearly equivalent to India's consumption, at around 60 Bcma. Natural gas accounts for 32% of the total primary energy supply mix in Pakistan and for nearly 52% in Bangladesh. Pakistan and Bangladesh are respectively the 21st and 33rd largest gas consumers in the world, with an established natural gas industry. To put it in context, Pakistan's gas consumption is nearly the same as in France while Bangladesh consumes 30% more gas than Poland.

Neither country has significant oil or coal resources. Both were self-sufficient in gas until 2005, however, increased demand fostered by lack of alternative fuels and price subsidies coupled with diminishing production constrained by unattractive fiscal terms have resulted in systemic gas and power shortages.

Bangladesh, which once considered the possibility of exporting natural gas in the wake of promising new gas discoveries offshore, is currently short of 5-10 Bcma versus domestic demand. Pakistan whose gas production is concentrated onshore is currently short of nearly 20 Bcma. Pakistan and Bangladesh are now developing LNG and pipeline importing schemes, but creditworthiness and low domestic prices pose a significant hurdle for the materialisation of the proposed projects. In total the two countries plan to import in excess of 10 mtpa of LNG and an additional 10 Bcma of pipeline gas.

In 2006 Pakistan issued a first call for tenders for the development of an integrated terminal/LNG supply (the Mashal Project). The tender was subsequently stayed by the Supreme Court in 2011 following allegations of irregularities. In October and December 2012 Pakistan issued two new calls for tenders for the delivery of 400 mmcf/d of regasified LNG each at Por Qasim, near Karachi. A decision on the tenders was expected to take place in early 2013 but again issues regarding the tender process have led to a halt in the project. A tender issued by Bangladesh in 2010 for the construction of an LNG terminal in the Moheshkhali Island in Cox's Bazar (Bay of Bengal) on a build, own, operate and transfer (BOOT) basis has been progressing very slowly.

At the moment, Pakistan is dealing with the increasing power and gas shortages through a significant use of fuel oil in power generation, sectorial gas allocation policies and the rationing of gas supplies to the once buoyant segment of compressed natural gas for vehicles. The 2006 Gas Allocation Policy recently revised by the Economic Coordination Committee (ECC) of Ministers sets priorities for the supply of natural gas by category of consumers, with the residential and commercial sector as priority number one.

On one hand, power shortages are a common feature in daily life in Pakistan and Bangladesh with serious impact on economic growth. On the other hand, both countries have been committing a large share of their GDP to the importation of crude and oil products due to the lack of other domestic supplies.

In addition to renewed efforts to import natural gas, both countries are stepping up investment in domestic exploration and production and developing enhanced fiscal terms to attract private investors to the domestic upstream. In 2012 the Government of Pakistan issued a new Petroleum Exploration and Production Policy aiming at providing more attractive fiscal terms for private investment in E&P. Bangladesh has released a revised Production Sharing Contract (PSC) and in December 2012 issued a tender for 12 offshore blocks with awards expected in early 2013.

Until now the Pakistan and Bangladesh mid and downstream sectors have been dominated by domestic gas players, with a handful of international companies participating in the upstream sector and contributing to a large share of the natural gas production. Given the existence of a well-established market and infrastructure for gas in both countries and taking into account government policy of maintaining a large share of gas in the energy mix, both countries may serve as large markets for E&P companies and for LNG and pipeline gas suppliers. The insertion of imported gas in the energy mix will depend on energy price reform, enhancement of fiscal terms and the implementation of an attractive investment framework to attract private investors.

Regional Overview and Economy

The Islamic Republic of Pakistan is a federal parliamentary republic comprised of four provinces (Balochistan, Khyber Pakhtunkhwa, Punjab, and Sindh), the Federal Capital Territory of Islamabad and the Federally Administered Tribal Areas. The People's Republic of Bangladesh comprises seven administrative divisions, or provinces: Barisal, Chittagong, Dhaka (the Capital), Khulna, Rajshahi, Rangpur and Sylhet.

Pakistan and Bangladesh are respectively the sixth and seventh most populous countries in the world with a population of 176.7 million and 161 million in 2012¹. According to the World Bank, Bangladesh is a low income country, with total nominal GDP of \$112 billion and GDP per capita of \$780 in 2011. Pakistan sits as a lower middle income economy with a nominal GDP of \$210 billion and GDP per capita of \$1,120 in 2011.

Over the last 6-7 years Bangladesh has maintained a stable GDP growth, around 6% per annum, which was not hugely affected by the world economic crisis in 2008. This can be explained by Bangladesh's lack of financial integration with the global economy, an increase in rice production, the resilience of garments and textiles exports mostly directed to the lower end of the consumer spectrum, and the robust remittance inflow from expatriate workers, mainly working in the Middle East. More than half of the GDP is generated by the service sector and nearly half of the population work in the agriculture sector².

In contrast, Pakistan's GDP has nose-dived since 2007 due to lack of adequate energy supplies, increased exports/imports imbalance, reduction in private investment and a growing fiscal deficit. According to the Asian Development Bank, energy shortages are seriously crimping

¹ CIA (2012)

² World Bank (2012)

large-scale manufacturing, which expanded by only 1.2% in the fiscal year 2011-2012. Power shortage is estimated to knock at least 2 % off GDP growth annually in Pakistan. The World Bank warned that “Pakistan faces significant economic challenges due to the sharp rise in international oil and food prices, combined with recurring natural disasters such as the 2010 and 2011 floods which had a devastating impact on the economy”³.

Although Bangladesh’s economy has been more stable, the country will need to treble the installed power capacity to nearly 20 GW and find another 8 Tcf of proven gas reserves, to maintain a GDP growth of 4.5-6% through 2030.

Figure 1: Comparative GDP growth in South-Asian countries

Energy Market Fundamentals

According to the International Energy Agency (IEA) natural gas accounted for 52% of Bangladesh’s total primary energy in 2009, or 74% of the total commercial energy supply. In 2009, natural gas represented 32% of Pakistan’s total energy supply, or 47.5% when only considering commercial supplies of energy. In 2009, total primary energy supply in Pakistan was 84.6 Mtoe against only 41.47 Mtoe in Bangladesh. Comparatively, total UK primary energy consumption was 203 Mtoe in 2011, more than twice Pakistan’s.

³ World Bank Pakistan Overview: <http://www.worldbank.org/en/country/pakistan/overview>

Figure 2: Pakistan and Bangladesh Primary Energy Supply

Source: IEA (2012a)

Coal

The participation of coal in the Pakistan and Bangladesh energy matrix is very limited. In 2011, coal consumption in Bangladesh was 1.0 Mtoe, and 4.2 Mtoe in Pakistan, which dwarfed in comparison to India's consumption of 295.6 Mtoe.

Proven reserves of coal in Pakistan totalled 2.0 billion tonnes in 2011 and were insignificant in Bangladesh. Pakistan produced only 1.4 Mtoe of coal in 2011. The coal potential of the country has been identified but large scale production is yet to be developed. The major coal reserves in the southeast province of Sindh, the Thar field are believed to amount to 175 billion tonnes, but the coal is of low quality and difficult to explore⁴.

Figure 3: Location of the Thar coal field in Pakistan

Source: Mansoor (2011)

⁴ Mansoor (2011), Page 6

The participation of coal in Bangladesh's energy mix is only 2%. According to the Ministry of Power, there are five coal deposits in Bangladesh, with total probable resources of 3.3 billion tonnes. Only one deposit has been developed, the coal field of Barapukuria, which started production in 2005, with a targeted capacity of 1 million tonnes/year.

Renewable energy

Pakistan has very limited experience with renewable energy other than biomass. A very high percentage of the population uses biomass energy (wood), particularly in rural areas; it is believed that the rural population meets more than 95% of its domestic energy needs by burning biofuels⁵. The Government created the Alternate Energy Development Board but only a few pilot projects have been implemented.

Bangladesh has extensive experience with biomass as most of the rural population cook on wood, tree leaves and dung residue. Biogas production is widespread, with thousands of households and villages in rural areas producing biogas from manure. Thanks to donor grants and soft loans, particularly from the World Bank and Asian Development Bank, there are more than 1.0 million solar photovoltaic (PV) systems installed in the country, totalling 25 MW as of November 2012, with plans to reach 2 million PV systems by 2016. Bangladesh has implemented one of the most successful solar PV programmes in the world with as many as 60,000 systems being installed every month⁶. In a bid to save expensive imported kerosene, the Government is planning to install 2,000 new off-grid PV systems by 2014, each one with an average capacity of 25 kW. Bangladesh is also in negotiations with the ADB to develop a 500 MW PV programme which will consist of grid connected and off-grid projects.

Hydro-electricity

The total installed generation capacity in **Pakistan** is 22,477 MW⁷, of which 30% is hydroelectric power plants. Pakistan has three large hydro plants, Tarbela (3,500 MW) Ghazi Barotha (1,450 MW), and Mangla (1,000 MW); the other hydro power plants are below 250 MW. The remaining hydro potential is 35 GW, with the possibility to develop 8,000 MW in the medium term; however the development of new projects has been delayed by political issues and lack of funding.

Bangladesh's total power installed capacity as of December 2012 was 8,525 MW. Hydroelectricity accounts for only 2.6%, circa 220 MW. There is only one medium-sized hydro plant in Bangladesh, Kaptai, built in the 1960s.

⁵ Pak-IEM (2011) Page 31

⁶ PV Magazine(2013): http://www.pv-magazine.com/news/details/beitrag/bangladesh--grameen-shakti-celebrates-one-millionth-installation_100009840/#axzz2UxyB8Ep3

⁷ HDIP (2011) (Page 48)

Figure 4: Pakistan share of commercial energy consumption and historic evolution

Petroleum

In 2010-11 Pakistan's crude production was in excess of 65,000 barrels/day, while Bangladesh production was below 1,500 barrels/day. Bangladesh consumes 104,000 barrels/day while Pakistan consumes 408,000 barrels/day which means a high dependency on crude and oil products imports.

Due to the lack of alternatives, limited refining capacity and high oil prices, the expenditure on crude and oil products imports in Pakistan and Bangladesh has risen to alarming levels. In Pakistan the import expenditures soared to more than \$15 billion in 2011, nearly 7% of the country's GDP. In 2012, Pakistan's oil import bill was recorded at \$2.8 billion during the months of July/August alone. Oil products imports accounted for \$2 billion of the total, led by fuel oil, gasoline and aviation fuel.

In the fiscal year 2011-2012 Bangladesh spent \$6.2 billion to import more than 100,000 barrels/day of crude and oil products, circa 5% of the country GDP. Nearly 17% of the imports were oil and diesel for power generation, a great share of this being consumed in rental oil-fired power plants and diesel generators for farming.

In addition to low energy per capita ratios when compared to other emerging markets, Pakistan and Bangladesh show a higher dependency on imported energy, particularly on high value oil products, which will contribute to further drag down their economic growth prospects.

Figure 5: Total energy supply per capita, select non-OECD countries

Source: IEA (2012b)

Figure 6: Ratio of imported energy supply to total energy supply

Source: IEA (2012b)

Natural gas overview

According to Pakistan's Ministry of Petroleum and Natural Resources (MPNR) and BP the remaining reserves of natural gas as of December 2011 are 27.5 Tcf (gas) and 342 million barrels (oil). Bangladesh's proven gas and oil reserves as of December 2011 are estimated at 12.5 Tcf and 28 million barrels respectively⁸.

Bangladesh and Pakistan are highly dependent on natural gas, which is the main fossil fuel produced domestically. They are some of the most gas-intensive countries in the world and natural gas makes up around 50% of their total energy supplies. Gas is extensively used as a fuel in the residential and commercial sectors and also fuels millions of vehicles as CNG. Natural gas also plays a major role in industrial development, power generation and in the agricultural sector.

Bangladesh and Pakistan gas consumption is significant when compared to several countries in east and north Asia. Bangladesh's at nearly 20 Bcma (2011) is higher than in the Philippines, Singapore and Taiwan. Pakistan's at nearly 40 Bcma is higher than Indonesia's and Malaysia's.

Figure 7: Natural gas consumption in Asian countries and Bangladesh/Pakistan – 2011

Source: BP Statistical Review of World Energy, 2012

Gas consumption in Bangladesh and Pakistan increased on average by 6% per annum over the period 2000-2011, with growth slowing over the last 3 years due to constraints in supply.

It is worthwhile mentioning that while India stepped up its exploration activities from 2005 to 2009, which resulted in substantial gas discoveries off the east coast, the evolution of Pakistan and Bangladesh gas reserves has been flat in the same period, as a result of less attractive fiscal terms, unsuccessful offshore campaigns in Pakistan and maritime boundaries issues with India and Myanmar, in the case of Bangladesh.

⁸ CIA Workbook (<http://cia-world-factbook.realclearworld.com/q/303/8048/How-many-oil-reserves-did-Bangladesh-have-in-2011>) and BP (2012)

Table 1: Key natural gas statistics – Pakistan and Bangladesh

	Pakistan	Bangladesh
Proven gas reserves (Tcf) 2011	27.5	12.7
Natural gas production (Bcma) 2011	39.2	19.9
Number of consumers (million) - 2011	6.0	1.96
Gas transmission & distribution (km) - 2010	119,989	20,804
Compressed natural gas (CNG) stations - 2011	3,500	555
CNG vehicles - 2010	2,740,000	207,000
Gas consumption by sector (Bcma) – FY2011		
<i>Industrial</i>	8.5	3.4
<i>Fertilizer</i>	6.4	1.8
<i>Power (+ captive power)</i>	9.9	11.1
<i>Residential</i>	6.8	2.5
<i>Commercial</i>	1.1	0.2
<i>CNG</i>	3.2	1.1
<i>Others (cement, tea plantations, losses, etc.)</i>	3.5	0.02
Total	39.4	20.12

Source: MPNR (2011), SSGC & SNGPL (Pakistan), Titas (Bangladesh), BP (2012)

According to BP the gas reserves in Pakistan stand at 27.5 Tcf (0.8 TCM) in 2011 while Bangladesh's gas reserves were 12.5 Tcf (0.4 TCM). The R/P ratios are 19.9 years (Pakistan) and 17.8 years (Bangladesh).

Figure 8: Evolution of Bangladesh, Pakistan and India proven gas reserves.

Source: BP (2012)

Pakistan: Gas markets and industry overview

Supply and demand of natural gas

According to the Petroleum Institute of Pakistan (PIP) forecasts⁹, the energy deficit in Pakistan will reach nearly 15 MTOE by 2020/21 even taking into account the projected imports of natural gas and coal (Figure 9).

Figure 9: Pakistan Energy Supply Deficit Trends

Source: PIP (2011)

The current official estimate of total gas demand in 2012 (actual plus unmet) is 55-59 Bcma¹⁰, against a domestic gas availability of 40 Bcma resulting in a 15-19 Bcma shortfall. In addition to the actual consumption of 40 Bcma there are at least 15 Bcma of unmet demand - fuel oil consumed in power plants and industrial premises and another 3-4 Bcma of unutilised capacity due to lack of fuel supply.

The Pakistan Institute of Petroleum (PIP) and PwC produced demand projections based upon GDP growth of 4.5% and 6.5% respectively, with demand rising to 63-71 Bcma in 2020, leading to a supply demand gap of 41-49 Bcma by 2020 (Figure 10). Pakistan's Government projections were less conservative, with demand forecast at 86 Bcma in 2020 but probably unrealistic due to the slowdown in the economy and lack of concrete alternatives. In any of the mentioned scenarios, there is considerable shortfall of gas supplies.

⁹ PIP (2011)

¹⁰ ISGS website: Conservative Scenario(PIP-Pakistan Institute of Petroleum), Optimistic Scenario: PWC analysis (Pakistan Interstate Gas Systems: http://www.isgs.pk/energy_sector.php?spid=22&mid=2)

In order to mitigate the shortfall the Government of Pakistan envisaged a mitigation plan consisting of the importation of natural gas by pipeline and LNG. The proposed importation schemes are indeed insufficient to meet the supply demand gap; therefore Pakistan will need to rely on imports of fuel oil and coal to meet its demand requirements.

Figure 10: Gas supply and demand forecast for Pakistan and proposed mitigation plan

Brief history of the oil and gas industry in Pakistan

The history of oil and gas in Pakistan dates from the 19th century, when the country was still part of India, under British rule. The first exploration well in Pakistan was drilled in 1887, in Mianwali, Punjab, followed by thirteen wells in Balochistan, which produced 25,000 barrels of crude during 1885-1892. Later the combined efforts of Attock Oil Company (AOC) and Burmah Oil Company (BOC) resulted in oil being produced in several fields in the Potwar region. After the independence of Pakistan in 1947, the Government promulgated the Regulation of Mines and Oilfields and Mineral Development Act of 1948 aiming at accelerating exploration and production activities in the country.

In 1952, gas reserves estimated to be over 10 Tcf were discovered in the Sui structure in Balochistan.

Following the natural gas discovery at Sui the Government of Pakistan signed gas concession agreements with several international oil companies - Standard-Vacuum Oil (1954), Hunt International Oil (1955), Shell Oil (1956), Sun Oil (1957) and Tidewater (1958) – leading to significant gas discoveries in several fields. However, since the discoveries didn't bear oil, exploration activities declined leading to the Government decision to undertake hydrocarbons exploration directly through newly established state owned companies, including Oil & Gas Development Corporation (OGDC), established in 1961 and later incorporated as OGDCL.

The other main government controlled company, Pakistan Petroleum Ltd (PPL) was first established in 1950, under the control of BOC. In 1997 BOC sold its equity in PPL to the Government of Pakistan. Currently PPL's shareholding is divided between the government (71%), PPL Employees Empowerment Trust (7%) and private investors (22%).

Successful exploration campaigns opened new gas provinces in Sindh, Punjab and Balochistan, all onshore. A total of 810 exploratory wells (since inception) have been drilled as of September 2012, of which 794 are onshore and 16 offshore. In 2010 the investment in drilling activities totalled \$ 810 million with 30 new wells drilled.

In addition to the state-controlled companies, several international companies are present in the Pakistan upstream such as BHP Billiton, MOL, ENI, OMV, Petronas, Schlumberger and Weatherford. BP was active in Pakistan for nearly 35 years, but divested its Sindh gas assets following the Macondo incident in 2010. ENI is currently the largest international player with production of 58,000 boe from its onshore blocks and participation in exploration in several offshore blocks.

Structure and organisation of the gas industry in Pakistan

The upstream activities in the oil and gas sector are administered and regulated through the Directorate General of Petroleum Concessions (DGPC) under the Policy Wing of the Ministry of Petroleum and Natural Resources (MPNR). The Policy Wing also comprises the Directorate General of Gas (DG Gas), Directorate General of Oil (DG Oil) and Directorate General Special Projects (DGSP) to provide support to the Government in formulation of policies for midstream and downstream of the oil and gas sector.

Figure 11: Structure of the gas industry in Pakistan

Source: OGRA, MPNR, SSGC

When compared to other emerging gas markets, the structure of the gas industry in Pakistan shows a few positive aspects: although the Transmission and Distribution companies have a quasi-monopoly¹¹ they do not own gas molecules therefore they don't compete with private gas producers in supplying the market. Also the gas distribution and transmission fees are much more modest than in countries like for example Brazil¹².

The independent Oil and Gas Regulatory Authority (OGRA) regulates midstream and downstream activities of the oil and gas sector. OGRA was formed under the OGRA Ordinance of 2002 to foster competition, increase private investment and ownership in the midstream and downstream petroleum industry and protect public interest.

The upstream segment is balanced between Government controlled companies (OGDCL and PPL), local private companies and IOCs, the latter responsible for nearly half of Pakistan domestic gas production.

Pakistan started developing its gas transmission and distribution infrastructure after the giant Sui gas discovery in 1952. The responsibility for gas marketing, transportation and distribution lies with the partially Government-owned gas utilities Sui Southern Gas Company (SSGC) and Sui Northern Gas Pipeline Ltd (SNGPL) which supply gas to the southern and northern provinces of Pakistan respectively. In addition to the two utilities, some independent pipelines are also present in the country, mainly catering for some power and fertilizer demand.

The few independent pipeline systems in Pakistan supply gas to power and fertiliser plants and are generally owned by Government companies i.e. Mari Gas Co. Ltd (MGCL) & Oil and Gas Development Company Ltd (OGDCL).

The total length of the independent pipeline system is nearly 300 km and gas supplies are of medium calorific value.

Table 2: Independent Pipeline Systems in Pakistan

Pipeline System	Length (km)	Capacity (Bcma)
MGCL: Mari field to Guddu Power Plant	60	1.8
MGCL: Mari field to Engro Fertiliser	20	1.4
MGCL: Mari field to Fauji Fertiliser	90	2.2
MGCL: Mari field to Fauji Fertiliser plant 2	15	1.0
Tullow Oil to Guddu Power Plant	33	0.4
OGDCL to Uch Power Plant	47	2.2
OGDCL to FKPC Power Plant	21	0.2
OGDCL to Altern Energy	10	0.3
Total	296	9.5

Source: OGRA

¹¹ Except for the few independent pipelines mentioned later in this chapter

¹² T&D fees: \$ 0.2-0.5/mm BTU in Pakistan, \$ 3.0/mm BTU in Brazil

The 2001 Petroleum Policy and OGRA's rules allow for third-party infrastructure access to existing T&D infrastructure and for direct sales to large consumers. SSGC & SNGPL have been given exclusivity until 2010 to supply gas to their existing customers. From 2012 onwards, any new industrial and power customer can be supplied gas via independent infrastructure; however this is yet to be implemented.

Figure 12: Gas infrastructure and main gas producing areas in Pakistan

Source: SSGC

Pakistan Upstream

The sedimentary basins in Pakistan cover 827,268 km² and the areas under exploration encompass 274,641 km², roughly one third of the total. The totality of gas and oil production comes from onshore fields.

There are currently 132 oil and gas licenses; 93 held by private companies and 35 held by OGDCL. There are 29 operators active in the country, from which 11 are local companies. The latest available production figures (October 2012) account for 42 Bcma of gas and 72,200 bopd of condensate. In the period 2008-2011, 32 concession agreements were signed covering an area of almost 68,000 km².

Figure 13: Pakistan sedimentary basins and upstream activities

Source: Pakistan Petroleum Information Service 09/2012, PPEPCA 2011

The offshore area of Pakistan consists of two sedimentary basins - Indus Basin and Mekran Basin Offshore - covering an area of about 300,000 km² - which are highly under-explored. Exploration in the Indus Offshore dates back to 1961 when a few international companies carried out seismic surveys and drilled 7 exploration wells between 1961 and 1978. Although gas shows were present, none of the wells found commercial quantities of hydrocarbons. At present there are 14 offshore licences which are being operated by UEPL (United Energy Pakistan Limited) ENI, and Niko Resources.

A Pakistan Basin Study Project has been recently carried out by the Government of Pakistan, covering all the sedimentary basins of the country with the objective of producing a consistent overview of all basins and a country wide review of the main prospective petroleum play fairways. The assessment of petroleum plays has reached the following conclusions¹³:

- Kohat Potwar Basin: Proven and potentially viable plays range in age from Infracambrian to Miocene.
- Central Indus Platform Basin: Proven or potentially viable plays, ranging in age from Infracambrian to Eocene.
- Lower Indus Platform Basin: Proven and potentially viable plays range in age from Infracambrian to Middle Eocene.
- Sulaiman Fold Belt Basin: Proven and potentially viable plays, ranging in age from Middle Jurassic to Middle Eocene.

¹³ Pakistan MPNR (2012 & 2009), PPEPCA (2011)

- Kirthar Fold Belt Basin: Proven and potentially viable plays ranging from Middle Jurassic to Lower Eocene.
- Northern Punjab Basin: Potentially viable plays ranging in age from Lower Cambrian to Pliocene.
- Pishin Fold Belt Basin: Potentially viable plays ranging in age from Middle Jurassic to Oligo-Miocene.
- Balochistan Fold Belt Basin: Potentially viable plays ranging in age from Palaeocene to Oligocene.
- Makran Fold Belt Basin (including Makran offshore): Potentially viable plays ranging in age from Middle-Upper Miocene to Pleistocene.
- Offshore Indus Basin: Potentially viable plays ranging in age from Lower Eocene-Middle Miocene to Oligocene-Neocene.

An assessment of Yet-to-Find reserves at an unrisks value for all of the basins studied suggests 3.6 billion barrels of oil and 66.3 Tcf of gas, but over the last few years there has actually been a decline in the country's gas reserves.

Figure 14: Evolution of Pakistan gas reserves

The critical issue for Pakistan is that the reserve replacement ratio is becoming negative and the production from existing hydrocarbon fields is on a steep decline: no large discovery has been made in the last few years. In September 2012, ENI announced a gas discovery onshore Pakistan north of its Badhra fields holding an estimated 300-400 Bcf of gas in place. Although the discovery was very welcome it barely meets Pakistan gas requirements.

Pakistan - Petroleum policies & fiscal regime

Under the Constitution of Pakistan, petroleum is a federal possession. In addition to its foundation legislation, the 1948 Regulation of Mines and Oilfields and Mineral Development Act, the government of Pakistan has regularly issued successive Petroleum Policies the first of which was in 1991. Subsequent policy improvements were issued in 1993, 1994, 1997, 2001, 2007, 2009 and 2012.

The main adjustments in the policies relate to prices, returns on investment and fiscal incentives. In January 2012 the Ministry of Petroleum released the new Petroleum Exploration & Production Policy aiming to increase the attractiveness of the sector to private investors. The policy envisages a system based upon Petroleum Concession Agreements for onshore operations and a system based upon Production Sharing Agreements for offshore operations. The 2012 Petroleum Policy introduces a floor of \$30/barrel and a ceiling of \$110/barrel for determination of the well head price¹⁴. An additional premium of \$1/MMBtu will be granted for the first three discoveries in each offshore area.

The process to apply for an Exploration and Production License is illustrated in Figure 15.

Figure 15: Application for grant of oil & gas concessions in Pakistan

Source: Pakistan Exploration and Production Data Repository¹⁵

The Petroleum Policy of 2012 establishes a domestic supply obligation, allowing companies to export their share of crude, condensates and gas at fair market prices subject to Pakistan net proven gas reserves being sufficient to meet projected gas demands over the next 15 years.

¹⁴ Varanese et al (2012)

¹⁵ <http://www.ppepdr.net/>

It also allows for E&P companies operating in Pakistan to contract with gas transmission and distribution companies and third parties (except residential and commercial consumers) for the sale of their share of gas in Pakistan at negotiated prices. However a gas windfall levy of 40% is accrued on sales to third parties other than government entities.

Subject to overall market demand, E&P Companies may request the government to purchase 90% of their share of pipeline specification gas through a nominated buyer and the E&P Companies retain the right to sell 10% of their share of pipeline specification gas to any buyer with the prior consent of the Government.

Other legislation of interest for E&P investors are the Territorial and Maritime Zone Act (1979), the Pakistan Environmental Protection Ordinance (1997), the Income Tax Ordinance (2001) and the Mines Act of 1926¹⁶.

E&P bid rounds

On October 10 2012, the Government of Pakistan issued an Invitation to Bid for Grant of Petroleum Exploration Rights for 60 onshore blocks (later reduced to 58 blocks), 35 in Zone I, 18 in Zone II, and 7 in Zone III. Bids were due in December 2012 but were postponed to March 10 2013 when, according to the Ministry of Mines and Petroleum and Natural Resources 66 bids were received for 50 blocks with an investment commitment of \$372 million.

Figure 16: Location of Pakistan's exploration zones

Source: Pakistan MPNR 2012 & 2009

A bid process usually starts when the government issues an Invitation to Bid in national newspapers and on the MPNR website. The invitation comprises nominated blocks as well as blocks deemed appropriate by the Ministry. The bid is valid for 60 days. Within 15 days of the

¹⁶<http://www.mpnr.gov.pk/gop/index.php?q=aHR0cDovLzE5Mi4xNjguNzAuMTM2L2lwbmIvcG9saWNpZXNEZXRhWxzLmFzcHg%3D>

bid date, if there are bidders offering matching numbers of the highest Work Units (minimum work programme units) they will be asked to re-bid. The bidder offering the higher Work Units in the re-bidding will be declared the winner.

The country has been divided into zones (see Figure 16) based on their relative prospectivity and geological risk.

There are three onshore zones;

- ZONE I: high risk - high cost areas,
- ZONE II: medium risk - high to medium cost areas and
- ZONE III: low risk-low cost areas.

There are three offshore zones

- Shallow
- Deep
- Ultra deep

The Government is providing different incentives for onshore and offshore areas. The key feature of the licensing bid is that prices for natural gas are determined upon a sliding scale of oil prices with a \$30/barrel floor and a \$110/barrel ceiling, and effectively capped at \$54/BOE; there are additional discounts applicable to the exploration zone and quality. In addition a windfall tax of 40% of the difference between the sales price and the zone price will be applicable to gas sales to third parties other than the federal and provincial government, effectively discouraging direct sales from producers to third parties.

For example, the producer prices for Zone II onshore and offshore deep-water at oil prices of \$110/barrel are calculated as follows:

Table 3: Producer gas prices 2012 E&P Licensing Round vs. 2009 Policy

Oil price \$/barrel	Gas price equivalent (\$/MMBtu ¹⁷)	Onshore @ 63.33% discount factor	Offshore Ultra-deep @ discount factor= 95%	Onshore price 2009 Policy ¹⁸	Offshore price Ultra-deep 2009 Policy
0- 30	5.26 @ \$30/barrel	3.33	4.99	2.96	3.84
30-50 = 30+50% of (P-30)	7.01 @ \$50/barrel	4.44	6.66	3.55	4.60
50-70 = 40+30% of (P-50)	8.07 @ \$70/barrel	5.11	7.67	4.02	5.21
70-110 = 46+ 20% of (P-70)	9.47 @ \$110/barrel	6.0	9.0	4.5	5.83
>110	9.47	6.0	9.0	4.5	5.83

The prices applicable in the 2012 Policy are 33-54% higher than the prices allowed in the 2009 Policy

¹⁷ Pakistan gas High Heating Value (HHV) 950 BTU/scf, conversion factor to BOE is 5.7

¹⁸ Discount factor for onshore Zone I: 67.5%. Discount factor for Ultra-deep offshore: 87.5%

Upstream bid package

The main features of the October bid package are as follows (Appendix 1 provides details for onshore and offshore blocks).

Onshore Zones

- 25-year lease, Royalty and Tax regime with royalty payable at 12.5% and corporate tax at 40%.
- Right of local E&P companies to take an interest in blocks operated by foreign JVs.
- Production bonus: \$600,000 to \$7 million depending on cumulative production thresholds.
- Minimum Work Programme based on best technical judgement rather than fixed number of units.
- E&P companies are allowed to charge a transmission tariff from the field gate to the entry of the transmission system if they build and operate a pipeline.
- Exploration period of 5 years with extension of up to 4 years.

Offshore blocks

- 25-year Production Share Contract with 5-year extension.
 - Royalties up to 12.5% and corporate tax of 40% can be recovered as cost. Government participation through profit share on sliding production scale instead of direct Government participation.
 - Costs recovery of up to 85% of the gross revenues.
 - Contractor profit share: depends on volume and offshore zoning. Minimum of 20% for shallower blocks and volumes above cumulative production of 1,200 million BOE and maximum is 95% for ultra-deep blocks with cumulative production of 0-300 million BOE.
 - Production bonus: \$ 600,000 to \$7,000,000 per annum depending upon volumes.
 - Gas Transmission Pipeline: The first pipeline connecting a field to onshore gas transmission system is allowed as cost recoverable, if such system is constructed and operated by the E&P Companies.
 - Exploration Period of 5 years with extension of up to 2 years.

Gas marketing provisions for onshore and offshore blocks

- E&P companies under Petroleum Exploration & Production Policy 2009 are allowed to contract with natural gas transmission and distribution companies and third parties, other than residential and commercial consumers, for the sale of their share of natural gas in Pakistan at negotiated prices.
- Subject to overall market demand, E&P Companies may request, and Government of Pakistan (GOP) will purchase, their share of pipeline specification gas through a nominated buyer which is effectively controlled by the Government (e.g. SSGC or SNGPL) in acceptable daily, monthly and yearly volumes to meet the internal demand in an economical manner provided there are no infrastructure constraints.
- The delivery point shall be at the field gate. GOP/gas buyer nominated by GOP shall pay the price for gas at the field gate as set out in the 2009 Policy.

- In case the foreign E&P Companies sell natural gas to third parties in Pakistan and want to remit sale proceeds in foreign currency abroad, Government shall allow such E&P Companies to freely remit a “guaranteed percentage” of their sale proceeds. The “guaranteed percentage” shall be 75% of the total gross revenues from any Lease in Zone O, Zone I, 70% in Zone II and 65% in Zone III. The remaining gross income in Rupees can be used to pay royalties, taxes, windfall levy and any other payments to the Government as well as to meet local currency expenditures.
- Prices for oil, gas and condensate determined by exploration zone, with floor and ceiling of respectively \$30/barrel and \$110/barrel.
- Windfall Levy (WLO) of 40% applicable on crude oil and condensate prices above \$40/barrel and for gas prices above zone prices.

Tight gas exploration policy

Pakistan MPNR and other authors estimate that the country holds 51 Tcf of Shale Gas reserves, plus estimated reserves of 2 Tcf for Low BTU Gas and 40 Tcf of Tight Gas¹⁹. Some authors estimate that shale and tight gas resources in place are around 240-280 Tcf.²⁰

The Tight Gas Exploration & Production Policy was issued in 2011 to establish the policies, procedures, tax and pricing regime in respect of exploration and production of tight gas in Pakistan. The 2011 Policy was based upon provisions of the 2009 Petroleum Policy and therefore will need to be revised to take into account the changes brought under the 2012 Policy.

The Policy provides incentives for gas discoveries that qualify and are accepted as “tight gas” under the existing and future exploration licences, Petroleum Concessions Agreements (PCAs) and Development & Production leases and that are not in production prior to notification of the Policy.

The Policy defines Tight Gas as a natural gas that a) cannot flow naturally at commercial rates with conventional methods despite having hydrocarbon reserves; b) requires advanced technologies for its exploitation/production such as high performance perforation, hydraulic fracturing, horizontal wells, multilateral wells &/or infill drilling or a combination of these technologies or any new technology acceptable to the Regulator; c) has estimated value of effective permeability less than “1.0 milli Darcy (mD)”.

The lease for tight gas is longer, 30 years, when compared to the lease under the 2012 Petroleum Policy, and can be extended for another 10 years.

In case of discovery of tight gas under an existing development and production lease, the lease shall be amended to separately include the D&P rights for the Tight Gas Reservoir or it is also possible to issue a separate lease. On the expiry of the D&P right for the conventional gas under the existing lease, the area held for the production of the conventional reservoir shall be relinquished, if it does not impede the production operation for tight gas wells.

¹⁹ Petroleum Institute of Pakistan (<http://www.pip.org.pk/shalegas.php>) and Khan (2011)

²⁰ Jadoon (2011)

The Policy also grants the right to the working interest owners to sell gas to third parties within Pakistan, at mutually negotiated prices between the Seller and the Buyer.

The Policy also allows for the suspension of production for a cumulative period of one year subject to technical and economic justification.

Figure 17: Location of Pakistan's unconventional gas resources

Source: M. R. Khan 2011

The Policy allows for a 40% premium for tight gas over the respective zone price of Petroleum Policy 2009 (see Table 4). An additional premium of 10% would be given for those volumes that are brought into production within 2 years of the announcement of the 2011 policy, applicable only to the volume achieved after the 2-year period.

Table 4: Wellhead price scenarios for tight gas in Pakistan

	40% premium (USD/ mmbtu)	50% premium (USD/ mmbtu)
PP '09 (Z III)	6.13	6.57
PP '09 (Z II)	6.59	7.06
PP '09 (Z I)	7.04	7.55

Source: Khan (2011)

Operating losses can be carried forward by a period not exceeding fifteen years. There is no windfall levy applicable to tight gas production. If both conventional and tight gases are produced from the same D&P lease, then the lease rental, production bonus, training fee and community welfare shall be levied once and shall not be duplicated.

The Tight Gas Policy should be reviewed after two years; therefore this should happen in 2013. However institutional mechanisms to oversee the implementation of the Policy are not yet in place.

Pricing policy for marginal gas fields

In early 2013 the ECC approved a pricing framework for marginal gas fields, which are defined as reservoirs which cannot be exploited economically under the existing E&P policies price structures. Gas prices for marginal fields will be set in accordance with the 2012 E&P Policy and the producers will be paid an additional premium of \$0.25/MMBtu above the corresponding onshore zonal price. The Government will keep its first right to purchase pipeline specification gas.

Gas marketing and pricing in Pakistan

SNGPL and SSGC are integrated utilities which operate the interconnected Transmission and Distribution grid. They buy gas from the producers at the delivery point (wellhead, gas treatment plant, or injection points), transport and distribute gas, under 10-25 years contracts at prices determined by the pricing policies in effect when the E&P concessions were awarded, and sell gas to end-users.

The Government has the first right to purchase all gas produced in-country either directly or through their government controlled companies. Neither SSGC nor SNGPL are involved in gas production. In 2005 the MPNR issued a Gas Allocation Policy establishing priority sectors for the allocation of natural gas. Under the 2005 Policy the residential and commercial sectors were first in the list of priorities followed by fertiliser plants. In the wake of continuous power shortages, the Policy was revised in 2012 by the ECC, with the following priority order: 1) residential and commercial; 2) power; 3) fertiliser; 4) cement; 5) CNG.

Gas prices for end-users are defined and approved by OGRA which also revises and publishes the producer prices in accordance to formulae defined by successive Petroleum Policies. The consumer price of natural gas in Pakistan comprises the following elements:

- The prescribed price for the gas companies, which includes:
 - Producer gas prices, which are linked with international prices of crude oil and HSFO
 - Excise duty
 - Transmission and distribution O&M costs
 - Depreciation of T&D Assets
 - Minimum return to the gas companies as stipulated in the World Bank/ADB loan covenants
- The Gas Development Surcharge (GDS) which is the difference between the prescribed prices and the actual consumer tariffs.

The prescribed price is designed to allow a fixed return on T&D assets. The prices are approved by OGRA and published in the Official Gazette, under the provisions of the license for transmission and distribution of natural gas.

The T&D companies (SSGC and SNGPL) are allowed by OGRA to operate on an annual return of not less than 17.5% on the value of their fixed assets, before corporate income taxes, interest and other charges on debt after excluding interest, dividends and other non-operating income. Any deficit or surplus on account of this is recoverable from or payable to the Government of Pakistan as a differential margin or Gas Development Surcharge (GDS) respectively. OGRA allows losses of up to 7% to be passed-through to consumers' prices, although it has set a benchmark of 4.5%.

The consumer tariffs are bundled and do not discriminate the different elements such as T&D charges and cost of supply. The tariffs are postalised, and do not take into account distance or volumes; each consumer pays the same price in its tariff schedule. The gas prices for end-users as of January 1, 2013 are as follows:

Figure 18: Pakistan end-user gas tariffs

End-user tariffs comprise two elements, a flat rate per volume applied to each category of consumers and a fixed charge (which is not shown on the chart above). In January 2013 the fixed rates ranged from \$1.46 (residential) to \$225/month (CNG).

The average sales price for SSGC as of March 2012 was \$4.34/mm BTU. On average the gas price for the end-user is not subsidised. The T&D companies pass-through their costs and earn an agreed rate of return on their investment. However the tariffs for some categories, such as residential and fertilizer and even industrial are low when compared to mature and emerging gas markets in other countries. Unaccounted for gas corresponded to 3.6% for SNGPL and 11.3% for SSGC in the year ending in March 2012, the average is nearly 10%. Late payment by Government owned entities, particularly power companies is substantial: in March 2012 SGNPL reported payment in arrears from the power companies around \$250 million.

Figure 19 compares Pakistan and Bangladesh industrial end-user prices with other international markets, both mature and developing. Bangladesh features prices below \$2/mm BTU which are only comparable to prices in the Middle East, whereas in Pakistan prices are close to USA industrial prices and indeed cheaper than in India.²¹

Figure 19: Pakistan vs International Prices - Large industries

Source: Brazil's MME (2012), ARSESP (2012), UK DECC (2012), BERC, OGRA

Table 5 shows that the current sum of all T&D costs and fees amounts to around \$0.4/MMBtu²². Although the margins are designed to guarantee a fixed return on SSGC and SNGPL assets, the companies have seen a steady decline in their profitability.

Table 5: Components of consumer gas price in Pakistan (Adapted to 2012)

Component	\$/MMBtu
Producers Price (net of royalty)	3.76
Royalty (12.5%)	0.54
Wellhead Price	4.30
Excise Duty	0.09
T&D costs	0.37
Return on Assets	0.23
Other incomes/equalisation	-0.18
Prescribed Price	4.80
GDS (Gas Development Surcharge)	0.05
Notified Consumer Price	4.85
General Sales Tax	0.78
Consumer Price	5.63
Price Break-up	
Producers' price	3.76
T&D Costs and other income	0.42
Taxes	1.44
Average Consumer Price	5.63

Source: Adapted from Nawab (2008)²³

²¹ Prices include taxes.

²² Figures do not include meter rental and connection fees

The current average wellhead price is relatively low in Pakistan when compared to India, \$3.76/MMBtu²⁴ due to old legacy contracts and because the Government-owned E&P companies receive a discounted price when selling gas from older fields, for example, Sui and Kandkot prices are respectively \$2.22 and \$2.18/MMBtu. On the other hand, the wellhead gas price in more difficult exploration areas such as Kadanwari is \$8.5/MMBtu.

In accordance with the policy guidelines issued by Government of Pakistan²⁵ the T&D company with a higher weighted average cost of gas will receive an equalisation payment from the other company of the amount necessary to equalise the cost of gas for both companies. In March 2011 this charge, from SNGPL to SSGC, was \$258 million.

Table 6: Field-wise natural gas wellhead prices in Pakistan

Fieldwise well head prices (01/07/12)		US\$/mm BTU	
Adhi	1.42	Miano	4.62
Bhit	4.97	Maramzai	2.71
Badin Deep fields	4.53	Manzalai	2.86
Badin-II, Badin-II Reviser	4.53	Nandpur Panjpir	2.71
Badin Compression	2.12	Norai Jagir	2.57
Badin Non-Golarchi Non	9.37	Pariwali	4.97
Bhadra	4.97	Pasaki	2.57
BOBI	6.60	Pindori	4.97
Chachar	2.26	Pirkoh	1.34
Chanda	2.76	Qadir Pur	2.61
Dakhani	1.42	Ratana	3.76
Dhodak	2.85	Sadkal	9.47
Dhumal	0.25	Sari Hundi	9.35
Hala (Adam X)	2.66	Sawan	4.62
Haseeb	2.22	Sui	2.18
Kandkot	2.29	UCH	3.92
Kadanwari	8.50	Zamzama	4.53
Khipro Mirpurkhas Block	2.66	Zamzama SNGPL	4.54
Loti	1.34	Zamzama Wapda/Guddi	4.58
Mamikhel	2.71	Zamzama - Phase - II	4.62
Meyal / Dhulian			1.25

Source: OGRA

Economic impact of gas and power shortages

The energy shortage is having a severe impact on Pakistan's economy²⁶. Most of the industrial and fertiliser plants cannot operate for most of the week, power plants are burning expensive imported fuel oil, there are daily rolling power blackouts ("load shedding") on a weekly basis,

²³ Updated and adapted by author to 2012.

²⁴ SSGC average purchase price March 2012 for Pakistan. India landfall prices: \$4.2 - \$5.76/MMBtu

²⁵ OGRA(2002)

²⁶ ADB (2012) (Page 179-181)

and gas for CNG vehicles is available for only to three days a week. Power shortages are damaging the exports of Pakistan products to international markets.

Fertiliser plants are being shut down or forced to buy diesel and fuel oil at higher prices, forcing the government to import fertilisers and sell at subsidised prices. Engro, the promoter of one of the LNG import schemes, has been particularly hit by the energy crisis as its brand new \$1.1 billion fertiliser plant has reportedly been shut down following government advice to SNGPL to suspend gas supply to the fertiliser sector and divert gas to the power sector in 2011. Engro is seeking damages around \$300 million from the gas company for breach of sovereign contract²⁷. According to fertiliser industry reports, the suspension of gas supply to four fertiliser plants has caused annual production losses of around 2.7 million tons of urea and will cost the country nearly \$1.4 billion in imported urea.

Subsidies to the power sector in 2012-2011 totalled \$5 billion against a budget forecast of \$1.5 billion²⁸. Power load shedding has been rolled out on a countrywide basis since 2008 and is a major issue, reaching nearly 3,000 GWh in summer. According to Pakistan Electric Power Company (PEPCO), the electricity shortfall is normally 2500 MW, reaching nearly around 6000 MW in summer. Most cities are facing 20-hours power outages, with widespread street protests, while restaurants and residential customers are reverting to the dangerous practice of installing “gas-sucking” compressors on supply lines to boost gas pressure in premises.

Pakistan started a very successful Natural Gas for Vehicles programme in the eighties, resulting in more than 3 million vehicles converted to Compressed Natural Gas (CNG), a very cost competitive alternative to diesel and petrol. Over the last 3 years, the gas shortage is forcing the Government to gradually phase out CNG – with no new licences being issued, and the Government is not allowing the renewal of gas supply contracts for the existing CNG stations²⁹. OGRA has granted permission to Pakistan State Oil to set up 26 LPG filling stations for vehicles in an attempt to divert natural gas from vehicles to power plants.

Over the last couple of years the Supreme Court has become increasingly active on energy matters. For example, the Supreme Court has recently taken up the matter of CNG price fixing by the government and OGRA in the larger public interest. In 2010 the Supreme Court effectively halted the LNG import project following allegations that the original bid rules have been changed.

To compound the difficulty there is also a heightened increase in security issues, following attacks on gas pipelines and transmission pylons in the province of Balochistan, which contributes to curtail gas supplies to cities in the region. There are areas in Sindh and Balochistan where SSGC is not allowed to collect the gas bills.

²⁷ The Tribune Express: <http://tribune.com.pk/story/399523/lawsuit-engro-claims-rs28-85b-in-damages-from-sngpl/>

²⁸ The Nation (2012): <http://www.nation.com.pk/pakistan-news-newspaper-daily-english-online/business/20-Sep-2012/oil-import-bill-surges-to-2-79b-in-2-months>

²⁹ Express Tribune (2012)

Figure 20: Load shedding in PEPCO's system - Pakistan

Load shedding on the PEPCO system, July 06-June 09

Source: ADB, Pak-IEM (2010)

In addition to not being able to meet the country energy demand for lack of supply, power and gas losses in Pakistan are very high. Electricity losses account for 17% of the electricity generated, due to transmission and distribution losses, inappropriate metering and theft. Gas losses vary from 4% to 11%.

In 2010 the Asian Development Bank (ADB) supported the Government of Pakistan to develop an integrated, full-sector, energy system planning model, the Pakistan Integrated Energy Model (Pak-IEM), which covers the whole energy system: supplies, refineries and power plants, transmission and distributions and end-users. According to Pak-IEM analysis, in order to allow for a 5.6% growth in GDP over the next 20 years, the following energy scenario is envisaged for Pakistan:

- Increase in electricity generation from 94,000 GWh to 410,000 GWh
- 82,000 MW of new power generation capacity additions
- Increase in consumption of oil products from 6.2 Mtoe/y to 18 Mtoe/y
- Significant annual savings can be achieved from energy efficiency and best practices. If implemented they could save over 20 Mtoe in imported energy in 2030.
- Eliminating load shedding avoids \$ 6.3 billion/y in economic losses
- Reducing electricity transmission and distribution losses by 7% saves \$75 million(gross)/y
- Improving end-use energy efficiency saves \$420 million (net)/y.
- Successful exploration to deliver 20% more gas saves an additional \$380 million (gross)/y.

The study also warns that under current practices and policies the proven reserves of conventional natural gas will be depleted by 2030 and energy imports are poised to increase from 27% to over 45% of total supply.

According to forecasts from the Ministry of Petroleum energy demand in Pakistan is projected to nearly double from 84.6 Mtoe in 2009 to 147 Mtoe by 2022, an annual average growth of 5.2%. Taking into account the need to reduce fuel imports the Government would like to change the energy mix, with a target of 30% for coal by 2030 and the increase in hydro from 1.3% to 33.6% in the same timeframe.

Gas import projects

In addition to enhancing the attractiveness of the fiscal regime to boost domestic gas exploration, the government is working in several areas to import natural gas via pipeline and as LNG. On the pipeline front, Pakistan has been negotiating natural gas import projects from Iran (IPI) and Turkmenistan (TAPI), whereas on the LNG front Pakistan has been trying to implement importation projects since 2006. Gas imports were originally planned to start by 2009 but so far no project has materialised. If Pakistan finally implements a fast-track LNG import project, this is likely to be commissioned by 2015.

Following preliminary import discussions with Iran in the nineties, the Inter State Gas Systems Limited (ISGS) was established in 1996 as a private limited company incorporated under ECC directives with the mandate of developing natural gas import projects. ISGS is funded by a tax imposed on natural gas sales by SSGC and SNGPL. The company is involved in the negotiations to import pipeline gas from Iran and Turkmenistan, while the LNG import project has been delegated to SSGC.

Figure 21: Proposed routes of the IP and TAPI pipelines

Source: IGS Ltd. Oxford Institute for Energy Studies.

Iran Pipeline Project (IP)

The Iran-Pakistan (IP) gas pipeline project was first discussed in the early nineties and in the early phases was intended to also supply India (formerly IPI Pipeline). Political mistrust, the imposition of sanctions on Iran, disagreement on transit fees and gas prices led India to abandon the project.

Iran plans to supply gas from the South Pars gas field to the Pakistan border. Each country would be responsible for the construction of the pipeline within its territory.

The pipeline route starts at the onshore gas plant at Assaluyeh in Iran, running 1,150 km up to the Iran-Pakistan border. According to information from ISGS, Iran has already completed a 900-km portion of 56-inch diameter pipeline from Assaluyah to Iran Shehr with the remaining 100-200 km to the border under design. The Pakistan section consists of 780 km from the border to the main transmission system intersection and it is yet to be built.

So far, the following agreements have been signed by Iran and Pakistan:

- An Intergovernmental Framework Declaration (IGFD), signed in 2009 by the Presidents of Pakistan and Iran.
- A 25-year Gas Sale and Purchase Agreement (GSPA) signed on June 5, 2009, with effective date of June 13, 2010. Contract volumes are set initially at 7.8 Bcma with target delivery date of December 2014.
- A Heads of Agreement (HOA) and Operations Agreement (OA) signed on March 16, 2010
- The price formula has been re-negotiated several times, and apparently stands at 13.4% Brent/JCC. Pakistan is asking to renegotiate the price to 12% Brent, in line with the price apparently agreed for the TAPI pipeline.

Former Secretary of State Hillary Clinton warned in March 2012 that ‘beginning the construction of (the) pipeline, either as an Iranian project or as a joint project, would violate (US) Iran sanctions law.’ On the other hand Russia saw the pipeline as an opportunity to avert the export of Iranian gas to Europe in competition with Russia’s export projects, and Gazprom declared its interest in participating in the Iran-Pakistan project.

However despite the threat of further sanctions, on January 30, 2013 Pakistan’s cabinet ratified a \$1.5 billion agreement with Iran for the laying the Pakistan section of the pipeline. Iran offered a package of \$500 million to finance the Pakistani side, comprising a loan payable in 20 years and supplies and equipment. The construction will be awarded to the Iranian company Tadbir Energy which is not a sanctioned company itself but it is an affiliate of the Imam Khomeini Foundation³⁰.

The Pakistani business community welcomed the decision of the government to implement the project. The new deadline to complete the project was set for 2015. According to the press in

³⁰ Critical Threats: (<http://www.criticalthreats.org/pakistan/jan-fulton-iran-pakistan-pipeline-moves-forward-despite-us-opposition-february-5-2013>).

Pakistan, of the remaining \$1 billion, financing will be arranged through a Chinese loan and \$ 500 million will be raised by Pakistan through the gas infrastructure development cess (tax) (GIDC).

What is not clear is how Iran will arrange the funding, given the restrictions imposed on its Central Bank. Lately, investors in China and Russia also seem reluctant to participate in the project. In early 2012, both Gazprom and the Industrial and Commercial Bank of China pulled out of the project. Another issue is whether Iran has sufficient gas reserves to supply the pipeline given the increasing demand in its domestic market. Other geopolitical issues such as Balochistan activism and the volatility of the Iran-Pakistan relations are also big hurdles for the implementation of the project³¹.

With presidential elections looming on the horizon for Pakistan (May 2013) and Iran (June 2013), the rekindling of the Iran-Pakistan project plays a convenient role in demonstrating that the incumbent governments are taking positive steps to solve the energy crisis on one side and bringing long needed external currency on the other side

TAPI pipeline

The Turkmenistan – Afghanistan – Pakistan – India (TAPI) project, also dubbed as the 'Peace Pipeline' was initiated in 2004 under the coordination of the Asia Development Bank (ADB) with the objective of supplying natural gas from the South Yolotan-Osman and adjacent gas fields in south Turkmenistan to Afghanistan, Pakistan and India.

The project consists of a 56-inch diameter, 1,680 km pipeline with design capacity of 33 Bcma of natural gas and CAPEX estimated at \$7.6 billion (2008). The gas buyers will be Afghanistan (5 Bcma), Pakistan (14 Bcma) and India (14 Bcma). The project completion was originally planned for 2017 and the gas will be sold under 30-year Gas Supply Agreements, with delivery agreed at the Turkmenistan border.

According to regional analysts, Turkmenistan indicates that the gas will be sourced from South Yolotan rather than from the Dauletabad field suggesting that it may be keeping gas from the latter field, which sources its internal East-West pipeline, to allow for future participation in the Trans-Caspian Pipeline through Azerbaijan.

The following agreements have been executed with regards to TAPI:

- Intergovernmental Agreement signed by the Head of States of all the member countries on December 11, 2010.
- Gas Pipeline Framework Agreement signed by petroleum ministers of the four countries on December 11, 2010.
- Heads of Agreement (HoA) signed by heads of commercial entities on September 19, 2010 and HoA for import prices in November 2011.
- Gas Sale and Purchase Agreement (draft) - Turkmenistan-Pakistan and Turkmenistan-India bilateral GSPAs signed by the heads of respective commercial entities on May 23, 2012.

³¹ Luft (2009)

- Memorandum of Understanding on “Long Term Cooperation in Gas Sector” between Afghanistan and Turkmenistan signed on May 23, 2012.
- Agreement on Transit Fee on April 17 2012. According to Pakistan’s MPNR, the participants agreed on transit fees of \$0.495/MMBtu. India will pay transit fees to Pakistan and Afghanistan, while Pakistan will only pay transit fees to the latter.
- Recommendation by the project steering committee in September 2012 to jointly form a Special Purpose Vehicle (TAPI Ltd.) with initial contribution of \$ 20 million to conduct feasibility studies and other project activities. The SPV will be equally funded by Turkmenistan, Afghanistan, Pakistan and India.

Road-shows with potential investors, coordinated by the project adviser, the ADB, were held in September 2012 in Singapore, New York and London. The project stakeholders are currently trying to attract a consortium to secure financing and manage the construction of the pipeline.

On February 7 2013, India’s Government decided to adhere to TAPI Ltd. The Indian Cabinet also approved the participation of the Gas Authority of India (GAIL) as India’s representative in the SPV.

Table 7: Estimate of TAPI price components in \$/MMBtu (oil@\$100/barrel)³²

	<i>Pakistan</i>	<i>India</i>
Turkmenistan border price	9.5	9.2
Transit fees	0.50	1.0
Transportation tariff Afghanistan	1.8	1.8
Transportation tariff Pakistan	-	1.0
Buyer country border price	11.9	13.0

Source: Author estimate

According to industry sources the agreed gas prices at the Afghanistan-Pakistan border are set at around 12% Brent³³, including transportation and transit fees. The price at the Turkmenistan border is estimated at \$9.2-9.6/MMBtu, nearly \$325-335/mcm, substantially higher than the border prices for exports to China estimated at \$241-247/mcm.³⁴

The project was devised as an alternative to the controversial Iran-Pakistan pipeline, and certainly has more supporters than the latter. It also fits Turkmenistan’s strategy of diversifying export markets for its gas. However it faces formidable obstacles, as it requires the stabilisation of Afghanistan, which would have 735 km of the pipeline running through its territory, in the provinces of Herat and Kandahar. It also requires credit-worthy buyers. So far only one of them, GAIL, has been involved in gas importing contracts, and the building of additional export capacity in Turkmenistan. The gas sector in Turkmenistan has suffered several capability and financial constraints and there are question marks over its ability to increase export volumes by 2020. According to Pirani’s estimates³⁵ Turkmenistan would be producing nearly 84 Bcma of

³² Author estimate, crude @ \$100/barrel

³³ Cutler (2011) and Express Tribune (<http://tribune.com.pk/story/367624/unanimous-decision-tapi-gas-transit-fee-finalised/>)

³⁴ Pirani (2012)

³⁵ Pirani (2012)

sales gas by 2020, of which 65 Bcma would be exported to China, Iran and other Central Asian markets. TAPI would require an additional 33 Bcma, representing a 50% increase in Turkmenistan export capability. This also means that Turkmenistan would have to increase the production of sales gas from 84 to 117 Bcma by 2020.

The project would certainly help to bring economic and energy integration to the region and it has been linked with the US Silk Route Strategy to connect Central and South Asia and aiming at consolidating American influence in Central Asia.

When the deals were signed in 2010, US State Department spokesperson Victoria Nuland hailed the signing as “a perfect example of energy diversification, energy integration, done right. We are very strong supporters of the TAPI pipeline.... We consider it a very positive step forward and sort of a key example of what we’re seeking with our New Silk Road Initiative, which aims at regional integration to lift all boats and create prosperity across the region.”³⁶

Since the events in second half on 2012 the project has not seen any substantial progress apart from official visits and political posturing. Investors are considerably nervous to put money into such a volatile region, and there is a need for a strong sponsor to tie the knots and implement the project. A 2017 implementation date seems unrealistic; if anything happens it is likely to be at the end of the decade.

LNG projects

In 2005 Pakistan announced its intent to import LNG and appointed SSGC to carry out a tender to develop a 3.75 mtpa terminal and regasification project in the area of Port Qasim, Karachi. The first LNG Policy was published in 2006 whereby the private sector was to play a leading role in the importation of LNG with the Government backing off providing guarantees for the projects.

Only one bid emerged from the tender, with little progress due to the lack of suitable credit guarantees. The Government then directed SSGC to issue a tender for an integrated project, the Mashal LNG project. 4Gas was selected to develop the integrated project but subsequently it was realised that the tender should be unbundled in two separate contracts, one for the terminal and regas facility and the other for the supply of LNG. The terminal project was handed to 4Gas and the Government created a special group to negotiate LNG supplies. GdF Suez won the LNG supply contract, with a deal reportedly offering 2 tranches of LNG supply³⁷:

- Tranche 1: 2.75 mtpa for six years, priced at (3.95%Brent + 75% maximum of Henry Hub-NBP + \$1.58)/MMBtu, equating to \$ 9.3/MMBtu (oil@\$70/barrel);
- Tranche 2: 1.5 mtpa priced at 15.2% Brent + \$0.5, for 20 years with price renegotiable after 10 years.

³⁶ The Economic Times (2012:): http://articles.economictimes.indiatimes.com/2012-05-24/news/31838940_1_tapi-pipeline-gas-pipeline-strong-support

³⁷ Dawn (2010): <http://archives.dawn.com/archives/43977>

Following complaints from other bidders reporting lack of adherence to the original bid (integrated project vs. unbundled project) the case landed in the Supreme Court which halted the signature of the 20-year, \$ 25 billion deal with GDF Suez in April 2010.

In 2011 the Government introduced a revised LNG Policy, aiming at providing additional incentives to the private sector, but which didn't change the overall structure of the LNG projects. According to the revised LNG Policy OGRA will determine the terminal and transportation tariffs but the final price of regasified LNG will not be regulated for sales to private sector consumers. However OGRA will determine the final price to public sector gas utilities such as SSGC and SNGPL. This poses a significant risk for the project developer since a substantial part of the gas price will vary relative to LNG prices. The project investor was also required to provide guarantees proving that it could meet its LNG supply obligations.

Since then a few private entrepreneurs have entered the LNG arena, for example Pakistan Gasport, , Engro's Elengy (EPTL), Global Energy Infrastructure (GEI), Daewoo (DSME), and Fauji Oil Terminal, which started the process of obtaining licenses from OGRA and was allocated pipeline gas capacity. However an import terminal is yet to materialise.

Brief summary of proposed private LNG projects

There are currently three floating LNG schemes being proposed around Port Qasim, and a fourth offshore-based outside the area. All of the three Port Qasim based projects will need additional pipeline capacity allocation from SSGC; two of them intend to use regasified LNG in their power and industrial facilities.

- GEI LNG – 500 mmcf/d
- Pakistan Gasport – 400 mmcf/d
- Engro Elengy (ETPL) Terminal Pakistan – 500 mmcf/d.

SSGC and SNGPL would have to increase the capacity of their pipeline system to accommodate for 4-8 Bcma of regasified LNG if two out of the three proposed projects are built.

The proposed projects are all located around the main and secondary channels of Port Qasim, near Karachi. There are another four proposed projects which didn't participate in the tender plus a new concept proposed by DSME of a floating offshore LNG terminal, in deeper waters. Apparently all of the three proposed projects in Port Qasim will require dredging to accommodate the berthing and manoeuvre of LNG ships, the dredging will fall under the responsibility of Port Qasim Authority and has not yet been started.

Figure 22: Proposed location of LNG import projects, Port Qasim, Karachi

Source: Port Qasim Authority, OIES

Engro Elengy Terminal Pakistan Limited, (EPTL)

EPTL, formerly known as EVTL, is a wholly owned subsidiary of Engro Corporation Limited, a Pakistani company engaged in terminals, chemicals and fertilisers. It aims to develop a 3.5 mtpa floating regas scheme. EPTL has already conducted a series of studies such as the Environmental and Social Impact Assessment (ESIA), Feasibility Study - Completed by Energy & Power (ENP) UK, the Quantitative Risk Assessment & Navigation Simulation Study, completed by Lloyd's Register, UK, and the NOC from Sindh Environment Protection Agency (SEPA). A conditional License from OGRA was granted for construction of the terminal with approval of the Quantitative Risk Assessment (QRA) and navigation simulation study undertaken with Lloyds is pending with Port Qasim Authority (PQA). EPTL has signed a term sheet with Excelerate, USA to provide a Floating Storage and Regasification Unit (FSRU) of 150,900m³ and has initialled an MOU with TCC China³⁸ for the EPC. EPTL has also engaged with IFC, ADB and others for project financing through a combination of debt and equity.

GEIP (GasPak)

The GasPak Project is an integrated 5 Bcma LNG terminal, pipeline and supply project being developed by the Global Energy Infrastructure Pakistan (Pvt) Ltd, originally from Turkey, in

³⁸ Tianchen Corporation China

Port Qasim. GEIP plans to build the LNG terminal at Chhan Waddo Creek in Port Qasim. The Project claims that it has obtained all licenses and permits necessary for the construction and operation of the terminal and for the sale and import of LNG/regasified LNG. Foster Wheeler has completed FEED. It plans to invest \$350-450 million and has arranged bridge financing from two private equity groups in Turkey, covering the complete cost of the project, which requires the construction of 18 km of offshore and onshore pipelines to connect with the SSGC transmission grid.

Pakistan GasPort Ltd (PGP)

The project is sponsored by local Associated Group, which owns LPG and lubes businesses in Pakistan. The Gas Port Project is located north of Qutub Point in Kadiro Creek, Karachi. The project comprises a 5 Bcma floating storage regasification unit, a jetty to berth the FSRU and LNG carrier, and a 5-km subsea pipeline to deliver regasified LNG to the SSGC transmission system. The project has been developed since 2007 and the sponsors say they have already signed an implementation agreement with Port Qasim Authority for the duration of the LNG project, completed site acquisitions for onshore and offshore facilities, conducted geophysical, bathymetric, and route surveys and navigation simulation, as well as the ESIA. The sponsors also claim to have signed a term sheet for debt financing with US OPIC.

DSME (Daewoo Shipbuilding and Marine Engineering Company)

DSME has come lately onto the Pakistan LNG scene with a proposal to develop an offshore floating LNG terminal. The terminal will be designed to regasify 3.5 mtpa of LNG on a floating regas unit located 22 km off the coast, requiring the construction of a sub-sea pipeline plus a 39 km onshore pipeline connecting to the gas transmission system. Gas would be offloaded through a turret system, requiring water depth of 45 m. The project has been granted a Provisional License by OGRA and has proposed an indicative tariff for the project. The DSME concept would require a ship-to-ship transfer at sea, with no break-water protection, which would allow operation for only 10-11 months/year. DSME did not submit a tender for the SSGC bid.

Regasified LNG (RLNG) tenders (2012/2013)

In the wake of the collapse of the Mashal project, the Government decided to start brand new LNG import initiatives in 2012. The government has also declared void and null a previous MOU signed with Qatar for the importation of LNG at a reported price of \$18/MMBtu.

In October 2012 the ECC approved the launch of three regasified LNG tenders totalling 10 Bcma aiming at supplying power generators. The government conceived the following phases:

- A Government-led fast track LNG project, for 2 Bcma of regasified LNG, using an existing LPG terminal in Port Qasim which will be modified to receive LNG vessels for a period of 2 years while the long-term projects are being built. There are question marks about the suitability of the site and the fact that only small LNG vessels could enter it.
- Two tenders for the purchase of 4 Bcma (circa 3 mtpa) each of regasified LNG (RLNG) for 15 years from private suppliers, with 5-year price reviews³⁹.

³⁹ Tender Enquiry SSGC/LNG03/2012 and Tender Enquiry SSGC/LNG-04/2013

The scope of services for the LNG tenders was the same, comprising the supply of regasified LNG (RLNG) to SSGC at a specified tie-in point, including LNG procurement, transportation, developing terminal facilities, storage and re-gasification of LNG and operating the terminal, under a 15-year firm off-take Gas Sales Agreement (GSA) backed by a sovereign guarantee from the Government of Pakistan with additional back up through multilateral development bank (MDB) guarantees. The tender established that the winner of the first import project will not be awarded the second (RLNG) project, to ensure diversity, and avoid monopoly and dependency on a single developer.

The government hired external adviser QED Consulting of the United Kingdom to assist in the tender and subsequent procurement process.

On October 17, 2012 SSGC issued a tender calling for Expressions of Interest due on December 3, 2012 for the first 4 Bcma LNG project. A reported 18 companies submitted expressions of interest but the subsequent tender due on January 9, 2013 attracted only 3 bidders, GEI Pakistan (GEIP GasPak); Pakistan Gasport (Gasport); and Elengy Terminal Pakistan (Engro). Unfortunately, one of the bidders submitted an incorrect bid guarantee, due to exchange rate discrepancies, while a second missed the time for delivery of the tender envelope by 18 minutes, resulting in only one compliant bid. After excruciating debates on whether to move forward with only one bidder, on January 30 the ECC decided to cancel the tender on the grounds of ensuring transparency through competitive bidding and ordered the call for a 3rd tender once the January 2013 tender was completed. The third tender is due on May 31 2013.

The second call for tender was published on January 6, 2013. The scope is the same as the first tender. Eleven companies purchased the tender documents but only 6 prospective bidders attended a pre-bid meeting held on February 6, 2013: Arif Habib Group, Global Energy Infrastructure Pakistan (Pvt) Ltd. (GEIP), FOTCO, Pakistan GasPort Ltd. (PGPL), Elengy Terminal Pakistan Ltd.(ETPL), and International Electric Power .

On the bid date, February 18, 2013, only the same three bidders of the previous tender submitted their tenders (Technical and Price Proposals): Elengy Terminal Pakistan Limited (ETPL), Pakistan GasPort Limited (PGPL), and Global Energy Infrastructure Pakistan (Private) Limited (GEIP). QED Consultants declared all the three bidders technically compliant. Based on the recommendation of the consultant, the price proposals of all the three technically complaint bidders were opened on March 5 2013.

The consortium led by Global Energy Infrastructure Pakistan (GEIP), reportedly with Exxon Mobil as the gas supplier, has offered RLNG at \$18.16/MMBtu. The consortium led by Pakistan Gasport Limited (PGPL), China Harbour Engineering Company and Gunvor, with Shell/ENI reported as LNG suppliers, offered RLNG at a price of \$17.71/MMBtu⁴⁰.

⁴⁰ Enerdata; http://www.enerdata.net/enerdatauk/press-and-publication/energy-news-001/pakistan-reviews-lng-import-tender_17490.html

The third consortium, led by Elengy Terminal Pakistan Limited (ETPL), with Conoco Phillips reportedly as the LNG supplier, submitted a conditional and multi-priced offer, based upon Brent and Henry Hub indexation which was deemed not compliant and was then disqualified.⁴¹

The federal cabinet has yet to give its approval for SSGC to sign a 15-year agreement with the lowest bidder. However before the federal government approved the results, the Supreme Court, alleging concerns about transparency, issued a stay order against all the proceedings until it passes a final judgment⁴².

During the proceeding, the court said that according to the media the ECC has failed to take a decision on award of a multi-billion dollar contract for import of 400 mmcf/d of LNG and left the matter to the federal cabinet to take this 'difficult decision'. It is worth noting that Pakistan is undergoing currently federal elections with a caretaker government in charge, so it seems unlikely that any award will be granted before a new government is elected in May 2013. In the meantime the Chairman of the SSGC Board tendered his resignation after the board was asked to declare the Gasport Consortium the successful bidder.

The fast-track project has also been put on hold because it was deemed to cause confusion with the RLNG tenders. Following the crumbling of the tenders, the MPNR announced that it has received an offer for 2 mtpa of LNG under a Government to Government deal with Qatar. Under the alleged offer Pakistan would be responsible for building the terminal and regas facility with Qatar responsible only for the supply of LNG. The price offered by Qatar was based on a formula equivalent to 14.9% Brent + \$0.6.⁴³

Will LNG projects be implemented?

Seven years have lapsed since the inception of the LNG import project in 2005 and despite local and foreign companies showing interest in the early days, there is no line of sight for the implementation of a terminal. In a best case scenario it would take another 2-3 years from the date of selection of a winning tender.

The insistence of the Government in developing the project as an integrated regasified LNG project concentrates the credit and market risks on the developers' responsibility. The local project developers need to commit to buy and re-sell a significant amount of LNG, 3- 5 mtpa, a very substantial burden for medium-sized local groups, particularly in the case of buyers who don't have high investment-credit ratings. Evidence from other LNG projects in emerging gas markets has demonstrated that implementation either requires a strong project champion for an integrated project - such as in Kuwait, India, Thailand or Brazil - or an unbundled scheme, where a government-appointed entity buys LNG and pays capacity fees to a separate terminal/regas developer, such as in Singapore.

As it stands today, the project developer in addition to guaranteeing the supply of LNG for 15 years and the terminal performance has only a few options to sell regasified LNG: a)

⁴¹ The Nation (<http://www.nation.com.pk/pakistan-news-newspaper-daily-english-online/business/08-Mar-2013/ecc-likely-to-approve-lng-import-contract-award-today>)

⁴² Pakistan Business Recorder, March 14 2013

⁴³ Pakistan Business Recorder, March 14 2013

Government-controlled buyers, with LNG prices determined by OGRA; or b) a myriad of power companies, some of them already in default of their fuel payment obligations and whose credit rate is not acceptable to underpin long term LNG supply contracts.

There is still a belief that Pakistan can attract LNG at prices below market levels, when the LNG supply outlook is still showing tightness in medium term supplies. The recent bid prices have shed some light on the actual supply prices. The developers have not been able to provide evidence to LNG suppliers that they can back \$ multi-billion LNG supply agreements with credit worth buyers.

There are too many private projects vying to attract and procure LNG supplies; this creates confusion as to which project is most likely to succeed. Since there is space to import more than 7 mtpa, the local developers should work together with a strong government-backed project leader to implement the project in closer cooperation.

Security and political instability in Pakistan, a perceived lack of transparency, the ongoing interference of the Supreme Court and the cancellation of the late 2012 and early 2013 tenders pose serious question marks about whether a LNG project will ever materialise in Pakistan.

Another key factor impacting the implementation of LNG projects in Pakistan (and also in Bangladesh) relates to how the Government will allow for LNG to be priced in the energy mix. The Government is proposing a weighted average price whereby LNG will be pooled with domestic natural gas for power customers only. It is not clear whether the weighted average price would apply only to IPPs or for the whole power sector, including state-owned power companies.

Fuel oil (HSFO) currently accounts for more than 35% of Pakistan's power generation. HSFO sales prices as of February 2013 were around \$22.3/mm BTU⁴⁴. Assuming that Pakistan can source RLNG at the latest bid prices (\$17.7/MMBtu), the pooled price with domestic gas would range from \$6/MMBtu if pooled with domestic gas for all consumers to \$10/MMBtu if pooled with domestic gas only for the power sector. Although much cheaper than imported fuel oil, the pooled gas prices would represent an increase in the current cost of supplies by 74%-187%⁴⁵. Figure 23 provides an illustration of the impact of LNG in Pakistan supply prices – the actual RLNG and HSFO prices vary with crude prices but are kept constant to facilitate a quick comparison.

Although the hefty increase when compared to current prices, the pooled price would be similar to the onshore domestic price for new discoveries established in the 2012 Petroleum Policy. Another possibility is for the Government to allocate LNG only for power plants currently consuming HSFO, but they will need to establish a mechanism allowing the plants to dispatch on base load to honour LNG take or pay agreements.

⁴⁴ Pakistan State Oil Company: HSFO import parity price for oil of kinematic viscosity of 180-centistokes, 16% sales tax included, internal freight not included.

⁴⁵ Brent at \$100/barrel

Figure 23: Comparative cost of supply for domestic gas and LNG

Source: Author estimate based upon published prices.

Opportunities for cooperation with India on energy matters

The energy crisis in Pakistan has prompted initiatives to develop a closer cooperation with India. In addition to cooperation on the TAPI Pipeline, India had offered to export 2 Bcma of regasified LNG to Pakistan which would be transported via a 60 km pipeline from Bathinda, in India to Wagah on the Pakistani border. Pakistan would need to build a 30-km pipeline from Wagah to connect with the SNGPL system. The conversations started in September 2012 and, according to industry sources, the parties have been discussing price formulas and whether the LNG price should be indexed to crude or fuel oil. Apparently India has been asking for prices above \$18/MMBtu, which were considered unaffordable by Pakistan. The latter would expect prices in the same range as the proposed TAPI prices, around 12% Brent at the Pakistani border. The prices quoted by India do not include transportation and fuel charges which could reach more than \$4.5/MMBtu⁴⁶. The parties are expected to revisit the price issues during 2013.

Energy-starved industries in Pakistan have started importing small and medium-sized coal-based power plants from India⁴⁷; the plants are below 10 MW. The companies will source local coal to reduce the consumption of high-priced imported fuel oil in their premises, with obvious adverse implications for CO² emissions and air quality

⁴⁶ Zone Asia-PK (2012): <http://zoneasia.wordpress.com/2012/12/06/pak-disagrees-with-indias-proposed-lng-transport-fee/>

⁴⁷ December 26, 2012 report in the Pakistan Recorder.

Pakistan gas markets: key findings and conclusions

If circumstances were different, Pakistan would be an ideal developing gas market for domestic producers or imported gas suppliers:

- A large existing consumer base, with anchor end-users in the power, industrial and CNG sectors.
- Large low-cost gas producing fields spanning in several sedimentary basins.
- A comprehensive gas infrastructure reaching important economic regions.
- Absence of a monopolistic and vertically integrated gas producer controlling the transportation infrastructure.
- Existing and long standing private gas producers.
- Evolving fiscal terms and domestic gas price policy acknowledging higher crude prices.
- Power consumers already using high-priced imported HFSO due to lack of alternative supplies.
- Unlike other developing markets such as China or India coal is not a serious competitor in power generation.
- A very large supply gap which could underpin either international pipelines or whole LNG projects.

Despite all the above virtues, Pakistan has been unable to implement any import project despite being involved in several pipeline and LNG schemes. The critical issues preventing Pakistan from securing gas to develop its economy can be summarised as follows:

- Political and security instability and absence of a national champion respected internationally, preventing large international companies becoming involved in the supply initiatives.
- Pipeline projects suffering from geopolitical issues and complicated transit routes. In addition Pakistan and India have not teamed together to lead such projects due to political mistrust.
- Domestic end user prices are still below market parity, requiring further adjustments to accommodate import prices.
- The fragile economic situation compounded by fuel payment defaults by power companies requiring continuous budgetary support creating a credit worthiness issue.
- LNG regulation still requiring prices regulated by OGRA when selling to Government controlled entities.
- Integrated RLNG concept with all risks borne by project developer requires strong balance sheet and appropriate credit support.
- Political interference and subsequent cancellation of three LNG tenders do not lend credibility to the proposed LNG schemes.

Pakistan would benefit from seeking feedback and understanding critical implementation factors from international companies and other LNG project developers. On the domestic front, further unbundling of SSGC and SNGPL allowing producers to access creditworthy buyers would also be supportive of the development of a more competitive gas market. Although not ideal when compared to natural gas, Pakistan could also look at its domestic coal supplies to provide some respite for power generation shortages caused by shortages of gas.

Bangladesh: Gas Market and Industry Overview

Brief history of the Bangladesh gas industry

The search for oil in what is now Bangladesh began in the later part of the 19th century through geological mapping⁴⁸. In 1890 the first oil discovery took place in Assam, followed in 2009 by a campaign led by the Indian Petroleum Prospecting Company. In the 1920-1930s Burmah Oil Company (BOC) drilled two shallow wells in Patharia with confirmed oil shows. The exploration activities were disrupted by the Second World War and the Independence movement in India.

Following the separation from India, Pakistan issued the Pakistan Petroleum Act in 1948, followed by concessions granted in the 1950s to The Standard Vacuum Oil Company (STANVAC), Pakistan Petroleum Ltd. (PPL), previously a Burmah Oil Company affiliate and Pakistan Shell Oil Company (PSOC). A total of 16 exploration wells were drilled discovering 7 gas fields.

The first national champion, Oil and Gas Development Corporation (OGDC) was established and started several exploration campaigns in 1961. Pakistan Petroleum Limited (PPL) discovered gas at Sylhet in 1955 in what was considered the first discovered hydrocarbon field in East Pakistan. Commercial production of gas commenced in 1960 with the supply of 4 mmcf/d to Chatak Cement Factory.

With the independence of Bangladesh from Pakistan in 1971, the branch of OGDC in Bangladesh was re-organised as Bangladesh Mineral Oil and Gas Corporation (Petrobangla). The Bangladesh Petroleum Act was enacted in 1974 and introduced a Production Sharing fiscal regime. The offshore area of Bangladesh was divided into 6 blocks, which were taken up by Ashland, ARCO, BODC (Japex), Union Oil, Canadian Superior Oil and Ina Naftaplin. After successive reforms, the activities of oil & gas exploration, production, transmission, distribution, oil importation, refining and marketing and mineral operations are carried by Petrobangla and its affiliates. The Bangladesh Gas Act enacted in 2010 establishes the framework for gas exploration, production and utilisation.

Structure and organisation of the gas industry in Bangladesh

The government plays a dominant role in Bangladesh's energy sector. Petrobangla is the key player in the entire oil and gas value chain, through affiliates operating in the upstream, mid-stream and distribution, and also in mining and marketing activities. The sector has undergone some re-structuring following the commissioning of a Gas Sector Masterplan⁴⁹ and strategic reviews from the major donors, the World Bank and Asia Development Bank. The restructuring comprised the separation of the activities of exploration and production from transmission, distribution and gas marketing.

⁴⁸ Petrobangla (<http://www.petrobangla.org.bd/>)

⁴⁹ Wood Mackenzie (2006)

Petrobangla's upstream affiliates are responsible for exploration and production; a gas transmission company operates the high pressure pipeline, whereas four gas distribution companies operate geographical franchise areas. There is some overlap between the gas distribution and gas transportation companies as the former still operate high pressure pipelines, which are being transferred to the transportation company on a phased timing. Another company is in charge of developing and marketing compressed natural gas (CNG) to end-users.

The participation of the private sector is significant in the upstream, with four companies accounting for more than 50% of Bangladesh gas production.

There is an independent energy regulator, the Bangladesh Energy Regulatory Commission (BERC) which oversees both the gas and power sector. BERC was established in 2003 and became effective in 2004. Its most recent policy guidelines⁵⁰ are the “Gas Development Fund Policy” in 2011, “Policy Guidelines for Enhancement of Private Participation in the Power Sector” in 2008 and a “Benchmark Indicative Cost and Pricing” in regard to the use of furnace oil, dual fuel (gas and furnace) and coal in private power plants. BERC is mostly a mid and downstream regulator; most of the upstream activities, such as issuing E&P and LNG tenders, are kept under Petrobangla supervision.

Figure 24: Structure of the oil and gas sector in Bangladesh

Source: BERC, Petrobangla

⁵⁰ BERC: http://www.berc.org.bd/index.php?option=com_content&view=article&id=95&Itemid=100

Exploration and Production

The Exploration and Production of hydrocarbons in Bangladesh is executed under Production Sharing Contracts. There are three state-owned companies engaged in upstream activities: Bangladesh Petroleum Exploration and Production Company Ltd (BAPEX), Sylhet Gas Fields Company Ltd (SGFL) and Bangladesh Gas Fields Company Ltd (BGFCL). BAPEX is engaged in both exploration and production; the other two companies operate existing producing fields.

- **BAPEX** is currently producing and supplying gas to the national grid from three gas fields Saldanadi, Fenchuganj and Shahbazpur, which has been brought under partial commission this year to supply gas to a rental power plant.
- **Bangladesh Gas Fields Company Ltd (BGFCL)** is the largest natural gas producing company in Bangladesh, accounting for 38% of Bangladesh natural gas demand. BGFCL operates six gas fields: Titas, Habiganj, Bakhrabad, Narsingdi, Meghna & Kamta, where operations have been suspended due to excessive water production.
- **Sylhet Gas Fields Ltd (SGFL)** operates 5 gas fields: Sylhet, Kailashtilla, Rashidpur, Beanibazar and Chatak with 13 producing gas wells.
- There are four International Oil Companies currently operating in Bangladesh: Chevron, Niko, Tullow and Santos. They account for 56% of the gas production in Bangladesh. Chevron operates Bangladesh's largest gas field, Bibiyana, responsible for 30% of the country's gas production. Tullow has announced its intent to leave Bangladesh to concentrate in other regions and Santos is considering its options.

Transmission and Distribution

The **Gas Transmission Company Ltd (GTCL)** is entrusted with the operation of the high pressure pipeline system. The concept of a National Gas Transmission Company was formulated in 1987 in line with the covenants of the World Bank Gas Infrastructure Development Project. The basic principle was the separation of transmission from distribution.

TCL was awarded the responsibility of owning, operating, maintaining and constructing all high pressure gas transmission pipelines in Bangladesh under a phased programme. GTCL is a fully owned subsidiary of Petrobangla. GTCL is gradually taking control of transportation infrastructure currently controlled by Petrobangla's production and distribution subsidiaries.

Figure 25: Bangladesh Gas Pipeline Transmission System (GTCL)

Source: GTCL

Distribution companies: There are 5 distribution/marketing companies with exclusive geographical franchise areas;

Titas Gas Transmission and Distribution Company Ltd (TGTDC)⁵¹ is the largest gas distribution company in Bangladesh. It was incorporated in 1964, formerly as a joint operation of Shell and the Government of Pakistan. TGTDC (or “Titas”) is now 100% owned by the Government of Bangladesh. Titas’s franchise encompasses the Greater Dhaka, Greater Mymensingh and Brahmanbaria areas. Titas owns and operates 735 km of transmission pipelines, which have not yet been transferred to GTCL and 7,585 km of distribution and service lines. Titas sells on average 14 Bcma (FY12), the power sector accounts for 54% of the total. The company serves more than 1 million consumers and is responsible for 80% of the market share in Bangladesh.

⁵¹ Titas : <http://www.titasgas.org.bd/>

Bakhrabad Gas Distribution Company Ltd. (BGDCL) is responsible for distribution and marketing of natural gas in Southeast Bangladesh, around the area of the Bakhrabad Gas field. The franchise area covers the districts of Comilla, Chandpur, Feni, Noakhali, Lakshmipur, and Ashuganj.

Jalalabad Gas Transmission & Distribution System Ltd. (JGTDSL) was formed in 1986 to carry out transmission and distribution of natural gas in the northeast part of Bangladesh, covering the Sylhet Division.

Pashchimanchal Gas Company Ltd. (PGCL) was established in 1999 with the objective of distributing natural gas within the Rajshahi Division.

Rupantarita Pakritik Gas Company Ltd. (RPGCL) was established in 1987 with the responsibility of fostering CNG in the transportation sector. The Company is also responsible for extraction and marketing of LPG, petrol and diesel obtained by fractionating Natural Gas Liquids.

Figure 26: Market shares of gas distribution companies in Bangladesh

**Market share gas distribution companies - June 2012
(Bcma)**

Gas supply and demand in Bangladesh

Bangladesh's gas sector saw sustained strong growth until 2005, at which point domestic production began to be a constraint. The consumption of natural gas has quadrupled in less than 20 years. In 2012 power generation (power sector and captive consumers) accounted for 60% of the overall gas consumption; there is a significant unmet latent demand due across all sectors due to supply constraints.

Figure 27: Gas consumption evolution by sector in Bangladesh

In 2012 the installed power generation capacity reached 8,525 MW, but the maximum realistic availability is only 6,350 MW due to a combination of old inefficient plants and lack of gas. If the gap of 2,175 MW was met with new gas-fired power plants, this would add 3-4 Bcma to the existing demand. Also if gas-fired plants replaced existing fuel oil and diesel generation, another 3.5-4.5 Bcma would be needed. In addition to these figures, Titas claims that the unmet demand in its franchise area is another 3-4 Bcma. Assuming that half of these requirements would come from sectors other than power the current unmet demand for natural gas could be as high as 30 Bcma⁵².

Table 8: Estimate of “hidden” natural gas supply demand gap in Bangladesh

	Gas demand (Bcma)
2,175 MW sub-utilised capacity	3 - 4
2,375 MW fuel oil/diesel plants	3.2 - 4.5
Titas deficiency (~50% non-power)	3.5 - 4
Current unmet demand	9.7- 12.5
Current gas consumption (2011)	19.9
Total current potential demand	29.6 - 32.5

Taking into account the current unmet demand, a GDP growth of 6% per annum and Power/GDP elasticity of 4%, slightly below the historic figures, the author estimates that the potential gas demand could reach 37 Bcma by 2015.

On the supply side, Bangladesh has managed to maintain a relatively flat supply profile, around 19-20 Bcma in 2010 and 2011⁵³. According to previous estimates from Wood Mackenzie for the

⁵² Author's estimate based on Petrobangla and the Power Division forecasts

⁵³ BP (2012)

World Bank⁵⁴ additional unproven reserves in existing fields could add 6 to 10 Bcma to the baseline production post 2015, whereas the Yet-to-Find reserves could add another 10 Bcma post 2020. The blocks offered in the 2012 E&P tender – if successful - will only be able to produce after 2020, therefore the Government is working on mitigation actions to keep production flat until 2015, through the drilling of additional appraisal/development wells and work-over of existing wells.

According to the author estimates the short term supply demand gap is expected to rise to 11-17 Bcma by 2015 (Figure 28). Petrobangla estimates that the country will need to produce 58 Tcf between 2011 and 2050 to meet its energy needs.

Table 9: Petrobangla’s long term overview of gas demand

<i>Sector</i>	<i>2011 – 2050 (Tcf)</i>
<i>Power</i>	37.3
<i>Fertiliser</i>	3.8
<i>Res/Com/Other</i>	4.4
<i>Industrial</i>	12.7
<i>Total</i>	58.2

Source: Petrobangla

Figure 28 : Short term supply demand outlook - Bangladesh

Source: Author estimate based upon Petrobangla’s forecasts⁵⁵

Bangladesh power sector

Electricity is a key element for the economic development of Bangladesh. According to the Ministry of Planning the elasticity of electricity consumption versus the rate of GDP growth is

⁵⁴ World Bank (2007) , Page 177

⁵⁵ Bangladesh Ministry of Finance (2010), Page 31

1.4 times⁵⁶. In the period 2008-2010 alone the average annual growth in consumption was 11% versus a GDP growth of 6-7%. According to the provisional estimates released by the Bangladesh Bureau of Statistics, the contribution of the power sector to GDP was 1.31% in the fiscal year 2010-2011, while the contribution from Natural Gas, Petroleum and Coal & Mineral Resources was estimated at 1.26% of GDP.

According to the BP Statistical Review 2012, the power sector in Bangladesh generated 42.7 TWh in 2011, which translates to a very low 270 kWh per capita, when compared to 470 kWh in Pakistan and 770 kWh in India. Bangladesh's installed electric generation capacity as of December 2012 was 8,525 MW, from which only 75% is available, with power shedding accounting for more than 2,000 MW. The losses in the power grid are also very high, amounting to 12.5 % of the electricity production in the fiscal year ending in 2011.

More than half of power generation in Bangladesh is supplied by Government-controlled power entities⁵⁷: Bangladesh Power Development Board (BPDB), Ashuganj Power Station Company Limited (APSCL) and Electricity Generation Company of Bangladesh (EGCB) are the largest ones. The private sector has 44% of the installed capacity but IPPs account for only 15% - according to the local press this is due to a slow paced decision-making process and lack of attractive economic conditions. In addition to the established power generators, the industrial sector has 1,200 MW of captive power capacity, and supplies an additional 88 MW to the national power grid.

Table 10: Ownership of power generation capacity in Bangladesh (December 2012)⁵⁸

Public Sector	Generation Capacity (MW)	Private Sector	Generation Capacity (MW)
BPDB	3700	IPPs	1297
APSCL	682	SIPP ⁵⁹ s(BPDB)/(REB)	325
EGCB	210	15-year rental plants	169
NWPGCL	150	3-5 year rental plants	558
RPCL	52	Quick rental < 2 years	1382
SUBTOTAL	4794 (56%)	SUBTOTAL	3731(44%)
Total		8525 MW	

Source: Bangladesh Power Development Board and Bangladesh Power Division

Over the last 3 years, more than 2,000 MW of fuel oil and diesel-based power plants were built in Bangladesh, most of them small to medium sized ‘quick’ rental units. In 2009 the Government pledged to increase the country’s power generation capacity from 6,000 MW to 13,000 MW by 2013⁶⁰. Due to time limitations, gas supply constraints and lack of other energy resources, the Government devised a power rental scheme, based upon short term rental of liquid fuel power plants owned by private developers (‘quick rental’). The rental power plants range typically from

⁵⁶ Bangladesh Ministry of Finance 2011 (Page 173)

⁵⁷ Ministry of Power, Energy and Mineral Resources: <http://www.powerdivision.gov.bd/user/brec/67/66>

⁵⁸ Bangladesh Power Development Board and Bangladesh Power Division: <http://www.bpdb.gov.bd/bpdb>, <http://www.powerdivision.gov.bd/user/brec/85/85>

⁵⁹ SIPP (Social Investment Program Projects), REB (Rural Electrification Board)

⁶⁰ Bangladesh Finance Ministry of Finance (2010) (Pages 10-13)

20 to 100 MW and consume High Sulphur Fuel Oil (HSFO). The scheme also contemplated the construction of peak-shaving power plants based on Diesel or HSFO. Nearly 30% of the installed capacity is made up of small power generation facilities operating under long term (15 years), medium term (3-5 years) and short term (1-2 years) schemes.

As a result, in just two years, there was a substantial change in the generation capacity profile. Natural gas' share fell from 88% to 67% whereas high sulphur content fuel oil (HSFO 3.5%) rose from 3 to 22%. The share of diesel which is more expensive trebled from 2 to 6%. The generation profile is now dominated by less efficient reciprocating engines which now represent 39% of the generation capacity.

Figure 29: Fast-changing generation power generation mix - Bangladesh

Since Bangladesh has very limited refining capacity, the demand for imported oil products has surged, and in 2013 the government is set to import more than 700,000 tonnes of fuel oil⁶¹

Figure 30: Generation capacity by plant type and fuel (December 2012)

⁶¹ HSFO 3.5% CST Singapore FOB

Table 11: Power plants commissioned in 2009 - 2011⁶²

MW	2009	2010	2011	Total
Public		255	800	1055
Private	356	270	125	751
Quick Rental		250	838	1088
Total	356	775	1763	2894

In 2010 the Government prepared a Power Sector Master Plan 2010 (PSMP-2010) with the declared objective of providing access to electricity to all by 2021⁶³. According to the Master Plan Bangladesh electricity demand will rise to 10,000 MW in 2015, and then 19,000 MW in 2020 and 34,000 MW in 2030. In order to meet the project demand the study called for the installed capacity to be increased to 24,000 MW in 2020 and 39,000 MW in 2030.

According to the existing generation expansion program, a total of 15,000 MW of new generation would be added to the national grid between 2010 and 2016, mobilising public and private sector investment. The plan was revised in 2012 calling for additional power capacity of 13,154 MW being installed between 2012 and 2016.

Table 12: Calendar-wise planned power capacity for Bangladesh (MW)⁶⁴

Year	2012	2013	2014	2015	2016	TOTAL
Public	632	1,467	1,660	1,410	750	5,919
Private	1,354	1,372	1,637	772	1,600	6,735
Power Import		500				500
Total	1,986	3,339	3,297	2,182	2,350	13,154

So far, 2,806 MW were added to the system from June 2009 to December 2012, nearly 800 MW per annum. There are nearly 1,100 MW being built, but most of the plants planned for 2013 onwards have not yet started construction, so it may be falling short of the 2016 target.

The government also plans to build four 500 MW coal-fired based power plants with public and private partnership in the Rajshahi and Chittagong regions. The priority now is to attract \$6 billion of private investment to build 5,000 MW of power capacity to help reduce load shedding to a tolerable level.

Similarly to Pakistan, Bangladesh is also managing the lack of adequate electricity supply by programmed power shedding.

⁶² Bangladesh Power Division

⁶³ PSMP (2010) (Summary: sections 3.1-3.3)

⁶⁴ PSMP (2010), (Summary: sections 3.1-3.3)

Figure 31: Evolution and impacts of staggered load shedding in Bangladesh

Source: Bangladesh Power Division.

Most of the rental and peak shaving power plants are quite small, ranging from 20 MW to 100 MW.

More recently some progress has been made in developing larger power projects. For example, in October 2012 APSCL signed a \$193 million Export Credit Agency loan with Standard Chartered for a 225 MW gas fired power plant followed by an EPC contract with Hyundai Engineering Company and Daewoo International Corporation. The plant is slated to start operation in early 2015. The reported tariff will be quite low around 16 \$ cents/kWh. APSCL signed a second \$ 420 million ECA with HSBC for a second 338 MW combined cycle power plant.

In December 2012, the Power Development Board signed contracts with Marubeni Corporation and Hyundai Engineering to build the 399 MW Bibiyana III gas-fired power plant. The EPC contractors will provide credit facilities for the construction of the plant. Bangladesh is also negotiating a \$ 467 million loan from Japan to build the 369 MW Bheramara CCGT plant.

The Government has signed a \$ 53.33 million loan agreement with the Saudi Fund for Development as part of the finance package for the construction of the \$ 270 million 225 MW Shikalbaha power plant in Chittagong, which was originally conceived to use fuel oil and then LNG.

The Government is also planning to develop the 1000 MW Rooppur nuclear power plant in cooperation with Russia. Apparently the Russian government will provide \$ 500 million for the initial phase of construction. The power plant is expected to cost \$ 3-4 billion.

Bangladesh upstream sector

Bangladesh has 23 gas discovered gas fields of which 17 are currently in production. According to Petrobangla, the estimated recoverable proven and probable reserve of the 23 gas fields is 20.6 Tcf from which a total of 9.79 Tcf has already been produced with a remaining recoverable reserve of 10.82 Tcf (as of June 2011). The daily gas production as of 10/02/2013 was 23 Bcma, from which Petrobangla and affiliates produce 10 Bcma and IOCs produce 13 Bcma. The average production in Fiscal year 2011 was 20.3 Bcma. There are 84 producing wells, 28 from IOCs and 56 from Petrobangla. The most prolific fields are the Chevron operated Bibiyana (8

Bcma) and Jalalabad (2.5 Bcma) and BGFCL operated Titas at 4.6 Bcma. Bibiyana also produces around 3,000 barrels/day of condensate.

Figure 32: Average gas production per field - FY2011

Source: Petrobangla

Nearly 132 wells have been drilled over the last 100 years in Bangladesh, 41 alone in the period 1990–2002. The number of wells drilled each year is about 2–3, with roughly one discovery for every 3 wells drilled. According to data extrapolated from a study by the Asia Development Bank⁶⁵, assuming a demand of 25 Bcma, a success rate of 1 in 3 wells, and assuming that smaller gas structures will bear an average of 0.25 Tcf, it would be necessary to drill 12 wells exploration wells per year to replace the domestic consumption. This would require investments in excess of \$20-30 billion and the development of a compelling investment framework to attract private investors.

The existing gas fields are producing at full capacity therefore to maintain production at satisfactory levels. Petrobangla is taking some mitigating steps⁶⁶, such as;

- Drilling 5 exploration wells at Kapasia, Srikail, Sundalpur, Sunetra and Mobarakpur expected to add 1 Bcma to current production. BAPEX is carrying out the work.
- Work over of 4 development wells at Titas Gas Field and work over of 1 well at Rashidpur gas field adding 1.4 Bcma.
- Launching a project for the importation of 5 Bcma of LNG (planned initially for 2013)
- Launching of an exploration tender in December 2012 for offshore hydrocarbon blocks

⁶⁵ ADB (2007)

⁶⁶ The Financial Express (2012): http://www.thefinancialexpress-bd.com/more.php?news_id=140656&date=2012-08-18

- Another 39 projects are under implementation by Petrobangla and its affiliates including 8 well-drilling programmes (exploration and development), 7 projects aiming to boost compression in the transmission system, and 2 seismic surveys.
- On April 26 2012 Petrobangla signed a \$194 million deal with Gazprom to drill 10 onshore wells in a bid to raise gas production by up to 3 Bcma. The companies plan to drill five development wells and five exploratory wells, with Gazprom working as a contractor on a turnkey scheme.

The 2012 Hydrocarbon Exploration tender

On December 9 2012 the government announced the 2012 offshore oil-and-gas-exploration tender inviting offers from international companies for exploring hydrocarbons in 12 blocks in the Bay of Bengal⁶⁷. The tender due date was March 18 2013. Awards are expected by mid-2013. The tender comprises nine shallow-sea blocks and three deep-water blocks.

- Shallow blocks: SS-2, SS- 03, SS- 04, SS- 06, SS- 07, SS- 08, SS- 09, SS- 10 and SS- 11, each having an exploration area between 4,500 and 7,700 square kilometres. The shallow blocks include the recently discovered shallow water fields of Kutubdia and Teknaf, which will be tendered under "special package" terms for exploration.
- Deep-sea blocks: DS-12, DS-16 and DS-21, each having exploration area between 3,200 and 3,500 square kilometres and a depth between 200 and 2,000 metres.

The technical qualification requires that the bidders demonstrate a track record of producing at least 15,000 barrels/day of oil or 150 mmcf/d of natural gas.

According to Petrobangla, the following companies purchased the bid documents and attended the first clarification meeting: Chevron, ConocoPhillips, ExxonMobil, Santos, Carnarvon Petroleum, Shell, CNOOC, ONGC, Cairn India, Kris Energy, ENI, Statoil, Premier Energy, and BAPCO of Bahrain.

The blocks comply with the March 14 2012 verdict from the International Tribunal for the Law of the Sea (ITLOS) that settled the maritime boundary dispute with neighbouring Myanmar. In line with the verdict, Petrobangla has dropped eight of the deepwater gas blocks offered in 2008 and excluded 11 others due to its maritime boundary dispute with India, whose arbitration is due 2014. Out of the territory under arbitration, ITLOS awarded Myanmar 171,800 square km (60%) while Bangladesh was awarded 111,600 square km (40%). No block disputed with India has been offered as the arbitration procedures are slated to start only in 2014.

⁶⁷ Platt's (2012) & Petrobangla: <http://www.petrobangla.org.bd/Bid%20Notice%20for%20Journal-6%20Blocks.pdf>

Figure 33: Blocks on offer in Bangladesh 2012 Offshore Licensing Round

Source: Deloitte⁶⁸

In the previous February 2008 licensing round, Bangladesh offered 28 offshore blocks, 20 in deepwater and 8 in shallow water, but the response was lukewarm due to the maritime boundary disputes, low gas prices and the relatively small size of the blocks. As a result of the bid Bangladesh decided to award two deep-water blocks to ConocoPhillips (10 & 11) and a shallow water block to Tullow Oil (Block 5). In the end the maritime border dispute prevented the signature of the PSCs and the issue was referred to the International Tribunal.

There is only one offshore producing gas block in Bangladesh - Sangu - previously operated by Shell, Cairn and currently by Santos, which once produced 1.7 Bcma but as of February 2013, production has declined to 0.13 Bcma. In 2012 Santos notified Petrobangla that it was terminating its operations in Bangladesh, due to the lack of growth opportunities⁶⁹, but in the wake of the announcement of the 2012 License Round it decided to continue operating the block until it remains commercially viable.

Highlights of the 2012 Petrobangla offshore bid

- Exploration Period: 7 years for onshore and 8 years for offshore blocks.
- Term: 20 and 25 years after Petrobangla approval of the Development Plan for oil and gas respectively, extendable for another 5 years.
- Maximum annual cost recovery: 55% of the revenues per Calendar Year.
- Biddable profit share on a sliding scale, from 5,000 to above 100,000 barrels/day for oil and 75 to above 600 mmcf/d for gas.

⁶⁸ Deloitte website: http://www.psg.deloitte.com/NewsLicensingRounds_BD_130414.asp

⁶⁹ Energy Bangla 2012: <http://www.energybangla.com/2012/11/17/2406.html#.UaloIkBwpnl>

- Contractor can dispose of gas freely but Petrobangla has first right of refusal and will pay a discounted price (1-5% discount).
- Gas Prices: Arithmetic Average Asian Petroleum Price Index for High Sulphur Oil 180 CST FOB Singapore, with floor at \$100/tonne and ceiling at \$200/tonne.
- Obligation to sell gas in the domestic market. Exports will not be allowed.

Although there is a slight increase in gas prices when compared to the previous PSCs, the prices are still quite low; in addition, there is a further deduction of 5% on fees and discounts to Petrobangla. The ceiling of \$200/tonne is equivalent to less than \$40/barrel. The chart on figure 31 illustrates the PSC 2012 prices at different HFSO prices. As of December 2012, HFSO FOB Singapore price was \$658/tonne, equivalent to \$16/mm BTU.

Figure 34: Bangladesh 2012 PSC price and linkage to HFSO FOB Singapore price

Source: Author estimate based on Bangladesh Model Production Sharing Contract 2012

Outcomes of Bangladesh 2012 Upstream Tender

On March 18 2013 Petrobangla opened the envelopes for the 2012 offshore blocks tender and the results were disappointing. Only two companies submitted bids for 3 separate oil and gas exploration licences in three shallow-water blocks: ConocoPhillips (Block SS-04) and India's ONGC Videsh (Blocks SS-07 and SS-09)⁷⁰. If awarded, ConocoPhillips will have the right to explore Bangladesh's first discovered offshore gas field, Kutubdia, which was offered under a 'special package' tagged SS-04 during the bidding round. Under the special package, the contractor will have to give an additional 5% of 'profit gas' to Petrobangla, in addition to the regular profit-sharing structure. It was reported that Kutubdia has a recoverable gas reserve of around 45.5 Bcf⁷¹.

Bapex will have a 10% interest in all the three blocks. The proposed investment commitment for the three blocks is \$183 million.

⁷⁰ Bangladesh Chronicle 2013: <http://www.bangladeshchronicle.net/index.php/2013/04/offshore-hydrocarbon-bidding-only-2-iocs-submit-bids-for-3-blocks/>

⁷¹ Source: http://www.epmag.com/Technology-Regulations/Bangladesh-Revising-PSC-Terms-Deepwater-Blocks_115112

Conoco Phillips offered to spend \$40 million on the exploration of block SS04 and has committed to conduct at least a 2,347 line km 2D seismic survey, 500 km² of 3D seismic and drill one well during the contract period. ONGC Videsh has committed to spend \$58 million for block SS-09 and carry out a 2,700 line km 2D seismic survey, 200 km² 3D seismic and drill two wells during the contract period. ONGC has committed to spend \$85 million on SS-07 and conduct at least a 2,850 line km 2D seismic survey, 300 km² of 3D and drill three wells during the contract period.

Some of the reasons cited for the low interest from IOCs are non-availability of primary data, low gas prices, and Petrobangla's right of first refusal to buy all gas production.

Gas marketing, pricing and affordability

Currently Petrobangla buys gas from the PSC contractors at prices fixed under the 1993 Petroleum Policy. Petrobangla has the right of first refusal and buys the cost recovery gas and contractor's share of profit gas but doesn't pay for the Government share of profit gas. There is no stamp duty or VAT on the price paid to the producers. Petrobangla is responsible for paying the corporate income tax to the Government on behalf of the PSC contractors.

Table 13 exemplifies the key features of existing onshore and offshore contracts:

Table 13: Gas prices for existing PSC contracts – pre 2012 Policy⁷²

Contract	Sangu (offshore)	Bibiyana (onshore)
Gas Price	93.75% HFSO	75% HFSO
Floor/Ceiling (\$/tonne)	70-120	70-140
\$/MMBtu	1.6-2.8	1.3-2.6
Government take (%)	57	66

Petrobangla then “sells” the gas to its gas distribution affiliate companies which are the exclusive marketers of gas in their franchise areas to all categories of consumers. The only exception is Santos' right to supply gas from Sangu offshore field directly to end-users at market prices, following the 2001 amendments to their Gas Supply and Purchase Agreement with Petrobangla. In 2012, Bangladesh Power Development Board reportedly started to buy gas from Santos at \$4.85/MMBtu⁷³ to supply a power plant in Chittagong.

Gas pricing to end-users

When selling to end-users the Government retains 55% of the gas sales and part of the proceedings goes into a Price Deficit Fund (PDF) to pay the PSC contractors. Petrobangla retains the remaining 45% to pay for its costs, including transmission and distribution margins.

In April 2003, the Government approved a new gas pricing formula where the Government producers' price will also be indexed to HSFO Singapore, with semi-annual price adjustments. The average end-user price is calculated according to the formula⁷⁴:

⁷² Wood Mackenzie (2006)

⁷³ The Financial Express: www.thefinancialexpress-bd.com/more.php?date=2012-06-18&news_id=133362

⁷⁴ ADB (2007) (Page 39)

- $CP = CG + TD + SD + VAT$, where
- CP = Customer Price
- CG = Cost of gas (75-93% HSFO, capped, for PSC volumes and 7% HSFO for Petrobangla gas)
- TD = Transmission and distribution fee = OPEX + 15% return on net fixed assets
- SD = Supplementary Duty, currently a fixed charge
- VAT = Value Added Tax = 15%

Each category of consumer pays a different tariff rate, according to Table 14, independently of the volume consumed and distance to the distribution system.

Table 14: Natural gas tariffs and cost of supply – Titas distribution concession

Consumer Category	\$/mm BTU (Effective 01/08/2009)⁷⁵
Power	0.99
Fertiliser	0.89
Captive power	1.46
Industry	2.05
Tea Garden	2.05
Commercial	3.31
Residential (metered)	1.81
Residential 1 burner (\$/month)	5.06
Residential 2 burners (\$/month)	5.09
Average cost of gas purchased from Petrobangla	1.30
Gross Distribution Margin	0.30
Average End-User Price	1.88

Source: Titas

The tariffs for gas for the power sector are some of the lowest worldwide, and do not even cover the cost of supply, whereas fertiliser plants pay prices only comparable to heavily subsidised prices in some Middle East countries.

As mentioned previously 22% of the power generation capacity is based on HSFO which is sold in Bangladesh at \$19.4/MMBtu. Since the power tariffs do not reflect the cost of supply there is an increasing amount of subsidy being borne by the Government to pay for imported fuel oil.

If the LNG import project materialises, and assuming that Petrobangla is able to secure RGLN supplies at the same prices proposed for Pakistan (\$17.7/MMBtu), it could opt to either pool LNG with the whole domestic production or with the power sector only. The LNG/power blended price for power plants would be one third of the current price being paid for imported HFSO.

⁷⁵ Exchange rate 12/02/2013: 79.02 Takas/\$

Figure 35: Bangladesh - comparative cost of gas supply with blended LNG

Source: Author estimates based upon published gas tariffs and prices.

Gas import projects

Pipeline import project

In 1997 a Bangladeshi company (Mohona Holdings) proposed the construction of a gas pipeline from Myanmar to India crossing Bangladesh. In 2000 the project was embraced by GAIL from India which was investing in exploration in Myanmar and thus interested in connecting the eastern regions of India with the rest of the Indian market. The Indian policy of actively looking to diversify from its heavy dependency on imported oil also focused on increasing the share of cleaner natural gas in the energy mix. In 2005 the three countries reached an initial agreement for the construction of the pipeline, which would cost nearly \$1 billion, with Bangladesh potentially reaping \$120 million/year in transit fees, but the project has stalled for 8 years, as Bangladesh and India could not entrust their security of supply to each other. GAIL considered other routes for the pipeline, all very costly, whereas Bangladesh considered the possibility of a bilateral pipeline with Myanmar instead of a trilateral pipeline. The lack of mutual understanding reached a point where Bangladesh introduced a provision in the 2008 E&P licensing round whereby contractors could export gas as LNG but not as pipeline gas. Sanctions imposed on Myanmar also hindered the international support needed to finance and build the pipeline.

After the election in 2009 of the Awami League Party, with a more pragmatic approach towards India, the countries resumed negotiations around the Myanmar pipeline, but it was too late as by

then Myanmar had signed a deal to supply China resulting in the construction of the Kyaukryu-Ruili pipeline.

More recently, Bangladesh became interested in participating in the TAPI pipeline, and in May 2012 the Government sent an initial proposal to the TAPI steering committee expressing its interest in becoming part of project. The proposal was initially accepted by the steering committee, but in parallel the Gas Transmission Company of Bangladesh prepared a feasibility study which concluded that it was not viable for Bangladesh to participate. The study points to the high transportation and transit fees and the need to build a 1,400 km pipeline from the point of delivery in India to Bangladesh.

Figure 36: Proposed route of the Myanmar-Bangladesh-India pipeline⁷⁶

LNG import project

In June 2010 Bangladesh announced its intention to import 5 Bcma of LNG to mitigate the gas supply shortage and started plans to build an LNG terminal. The site of the proposed terminal is Moheshkhali Island, near Cox's Bazar, which requires a 90 km pipeline to connect the terminal to the gas transmission system in Chittagong. In November 2010 Bangladesh issued an initial invitation for Expressions of Interest for an unbundled LNG import terminal with regasification capacity of 5 Bcma with berthing and mooring facilities to accommodate LNG ships with capacities from 138,000 to 260,000 m³. The terminal will be built on a build-own-operate-transfer basis with a 15 year operating licence⁷⁷.

⁷⁶ Chandra (2012)

⁷⁷ Petrobangla and Bangladesh Chronicle: <http://www.bangladeshchronicle.net/index.php/2013/03/ambitious-unrealistic-plan-puts-countrys-energy-quest-in-dilemma-experts/>

In order to oversee the execution of the project the Government created a special LNG Taskforce chaired by a former Bangladesh officer, who had a realistic view of LNG prices, quoting DES prices of \$ 8-10/mm BTU as “market prices” in 2010. Petrobangla expected to complete the terminal by 2013. In parallel to a call for Expression of Interest (EOI) to build the LNG terminal, Bangladesh signed a memorandum of understanding (MOU) to import 4 mtpa of LNG from Qatar Petroleum.

The call for EOIs received applications from 10 companies - GdF Suez, BW Gas Norway, Golar LNG, Vitol, Samsung South Korea, JV Astra Oil and Excelerate, Teekay Shipping, Hiranandi Pvt Co of India/Hoegh LNG, Ros Roca Group of Spain and local Unination Energy Ltd. The subsequent bid attracted lukewarm reactions and the tender stalled for a few months.

In September 2011 Poten & Partners was retained by Petrobangla as the adviser for the implementation of the international tender for building the LNG terminal, LNG transmission and marketing in Bangladesh.

After a protracted tender process, in January 2012 Petrobangla shortlisted 4 bidders (Golar, Astra Oil & Excelerate Energy, Samsung and Hiranandani Electricity Pvt Ltd.) to present proposals for the construction of the terminal.

In May 2012 Qatar proposed setting up a 1,000 MW LNG-based power plant near the proposed site for the LNG terminal under a joint-venture initiative with Bangladesh.

The Astra Oil/Excelerate Energy consortium was selected for negotiations in August 2012 but it failed to reach agreement with the Government. According to a Platt’s report, the consortium quoted a regasification fee of \$0.39/MMBtu which did not include onshore and offshore transmission costs. In addition to the regas fee the consortium asked for EPC fees and credit support. The project didn’t show any progress until February 2013, when the Indian company Hiranandani Electricity rekindled the idea of building the terminal⁷⁸.

Despite the acute energy crisis, the LNG project is unlikely to materialise in 2015 due to issues such as credit worthiness of the Buyer, poor connectivity between the terminal and supply projects, lack of funding/finance to build the terminal and lack of a strong project sponsor. The project would benefit if multilateral agencies such as the World Bank and Asia Development Bank could provide guarantees for the LNG buyers and equity injection in the project.

Opportunities for cross border cooperation

The election of the Awami League Party in Bangladesh, which has closer ties with the ruling Congress Party in India, has created on one hand a more pragmatic approach to commercial relations and bilateral trade. On the other hand India has become more conscious and active in its role as the regional superpower thus exerting more influence in the neighbouring countries.

⁷⁸ Business Standard (2013): http://www.business-standard.com/article/companies/hiranandani-in-race-for-bangladesh-s-first-lng-terminal-113020500094_1.html

In addition to conversations about gas pipelines, Bangladesh and India started a formal cooperation on energy matters by signing an MOU in November 2009⁷⁹. A Joint Steering Committee chaired by the power secretaries of the two countries and a Working Group will look for opportunities for grid connectivity, power exchange, joint investment in power generation, and capacity development. In addition, India is also proposing the construction a 1,320 MW coal-fired power plant in Khulna, Bangladesh.

The Working Group identified an opportunity for power interconnection between Bheramara in Bangladesh and Baharampur in India, including a 400 KV, 30 Km power line and a substation at Bheramara. The project will allow a power flow of 500 MW into Bangladesh. The \$100 million project is financed by the ADB, backed by a 250 MW power purchase agreement signed in 2012 by NTPC Vidyut Vyapar Nigam Ltd (NVVN), a subsidiary of India's NTPC and Bangladesh Power Development Board (BPDB). The construction has already started and commissioning is expected by late 2013.

The opening of power trade will also facilitate new investments from India's private sector into the Bangladesh power and gas sectors.

The cross-border trading with India opens the possibility for power trading between Bangladesh and Nepal and Bhutan which have a considerable hydro potential. Bangladesh has started negotiations for power trading with Myanmar targeting the importation of 500 MW by 2017 but Myanmar has recently declared itself not to be ready to export electricity.

Critical energy issues impacting Bangladesh

Despite Bangladesh emerging relatively unscathed from the 2008/9 economic crisis, the recent energy crisis has been a serious burden to the country's economy. According to the World Bank⁸⁰, the lack of a reliable supply of power and gas remains a major constraint on businesses. While total gas production has increased 7% between 2009 and 2011, gas sales to the power sector have declined 20.3%, as scarce gas is diverted to residential and CNG consumers. The ensuing power shortage has caused disruption in industrial production, particularly in the clothing, ceramics, fabrics and steel industries. Although large factories have their own power generation kits, they also suffer due to gas shortage. The World Bank⁸¹ estimates that most industrial facilities in Bangladesh are operating at half of their installed capacity due to a lack of reliable power and gas.

The annual loss of production and income from power outages could exceed 0.5% of GDP per year.

Likewise in Pakistan, the energy shortage is forcing the closure of smaller businesses, shutting down fertiliser plants, and causing the rationing of gas for residential and CNG consumers.

⁷⁹ Energy Bangla: <http://www.energybangla.com/2013/04/16/2625.html#.UZDyNrVwpnI>

⁸⁰ World Bank (2010) (Page 3)

⁸¹ World Bank (2010) (Page 7)

Less than 50% of the population has access to electricity with a per capita availability of 270 kWh/year. Problems in Bangladesh's electric power sector include high system losses, delays in completion of new plants, low plant efficiencies, erratic power supply, electricity theft, rolling blackouts, and shortages of funds for power plant maintenance.

The Bangladesh Textile Mills Association claims that irregular gas supply caused a 50% decline in textile production, one of the country's economic mainstays and the Bangladesh Knitwear Manufacturers and Exporters' Association asserts that orders can no longer be fulfilled due to lack of gas. In addition to electricity load shedding in 2010 the Government started a gas rationing system whereby factories will have to shut one day a week.

In an attempt to mitigate the power crisis, the Government entered into contractual arrangements with small power producers and rental power plants, which in turn consume imported diesel and fuel oil. As a result, the burden on the federal budget is quite substantial. In the fiscal year 2011 the Bangladesh Petroleum Company (BPC)⁸² imported 230,000 tonnes of HFSO to supply the rental and peak shaving power plants with delivered value of \$153 million. In 2012 the volume of imported HFSO more than doubled to 680,982 tonnes with delivered value of \$496 million.

In the fiscal year ending June 2013, BPC is planning to import 5.9 million tonnes of crude and oil products, an increase of 11% from the previous year. It will import 1.4 million tonnes of crude oil, 3.0 million tonnes of diesel, 1.2 million tonnes of HFSO and a combined 300,000 metric tonnes of kerosene, jet fuel and octane. The oil import bill is expected to rise to \$ 6.2 billion, equivalent to 5% of Bangladesh's GDP.

Sales of HFSO have quadrupled in 3 years with the power sector accounting for 19% of the market for oil products in Bangladesh.

Figure 37: Evolution of HFSO and share of the oil products market in Bangladesh

⁸² <http://www.bpc.gov.bd/contactus.php?id=13#>

Subsidies

Direct and cross subsidies are widespread in Bangladesh. BPC sells oil products below market parity. It requested \$350 million in subsidies from the Treasury for the period July-September 2012, but it was allocated only \$182 million. BPC also borrows money from the Islamic Development Bank to fund oil imports; it is expecting to borrow \$11.0 billion over the period 2013-2016. This sum includes \$2.0 billion already borrowed by BPC for the current Islamic calendar year which started on November 15 2012.

Although contributing almost \$390 million to the Exchequer in the fiscal year 2011, BPC made a loss of in excess of \$1.1 billion in the same fiscal year⁸³.

In the power sector, the Government has estimated that the Power Development Board (BPDB) will need subsidies of \$800 million for the fiscal year 2013 to buy 20% more electricity from fuel oil-fired rental power plants. In the fiscal year 2012 the subsidies amounted to \$826 million⁸⁴.

In order to reduce the amount of subsidies, the Government is asking BPDB to run rental power plants at 35% capacity, instead of the 55 % recommended by BPBD. BERC has increased the price of power sold by BPDB to the distribution companies by 16% in September 2012 but it was not enough to neutralise the losses. BPDB buys electricity from rental plants at \$160/MWh and from the public sector at \$24/MWh; the average cost of supply is \$76.9/MWh for the fiscal year 2013. It then sells electricity at \$58.7/MWh, incurring losses of \$18.2/MWh⁸⁵.

The situation will likely be aggravated in the near future. By 2016 the Government plans to add 2600 MW of coal-fired power plants plus 1,135 MW of gas/diesel/LNG plants. They would require 2 Bcma of gas which may not be available, whereas the coal-fired plants are not yet being built. Therefore in order to avoid the worsening of the energy crisis the Government will have to resort to more, rather than less HFSO-fired power generation.

Table 15: Planned Power Generation Fuel Mix in 2016⁸⁶

<i>Gas</i>	<i>Gas/Diesel</i>	<i>HSFO</i>	<i>LNG</i>	<i>Coal</i>	<i>Solar</i>	<i>Wind</i>	<i>Imports</i>
6169 MW	1501 MW	1691MW	225 MW	2938 MW	23 MW	100 MW	500 MW

Source: Bangladesh Power Division

Bangladesh gas market overview: key findings and conclusions

Bangladesh economic resilience is being hurt by the growing cost of oil imports and lack of gas supply for power generation. In the medium term there is no other supply alternative either in the domestic or imported supply arena. The Asia Development Bank estimated that a minimum

⁸³ Star Business Report (2013)

⁸⁴ Hossan (2012): slide 12

⁸⁵ BERC website: www.berc.org.bd

⁸⁶ Bangladesh Power Division website

growth rate of 8%/year in gas production will be required to meet the Government's GDP growth target of 5–6%/year⁸⁷.

Although having a reasonably large gas market, the extremely low domestic gas prices are not only deterring IOCs from participating further in the upstream but also undermining Petrobangla's upstream capabilities for further gas exploration, appraisal and development. Gas price reform is still very timid to encourage efficient utilisation particularly in the fertiliser sector which operates very old and inefficient ammonia-urea plants.

Bangladesh doesn't possess large unexplored hydrocarbon basins and the blocks on offer in 2012 were relatively small compared to other global sedimentary basins. The proposed fiscal terms were not sufficiently attractive when compared with Pakistan, for example, and there are still unresolved disputes with blocks near the India border.

Bangladesh will need to step up further improvements and re-bid the remaining 6 offshore blocks, as Myanmar⁸⁸ is putting together its first upstream bid due in June/July 2013.

Bangladesh also missed the window to develop the Myanmar pipeline in cooperation with India due to political mistrust. Although the ruling party is much closer to India's Congress Party, which facilitates cooperation in energy matters, China is now a dominant player in Myanmar's gas scenario. There has been good progress in Bangladesh on renewable energy due to massive grants/loans from multilateral agencies but this will not be sufficient to meet the unsatisfied demand of energy.

Similarly to Pakistan, Bangladesh needs to step up domestic gas exploration and speed up the implementation of the LNG project, allowing the construction of more efficient combined cycle power plants. The LNG project will require a project champion with a strong balance sheet, the provision of strong credit support and guarantees, a more flexible LNG supply contracting policy, with a mix of short and long term agreements and some degree of pricing pooling/aggregation with domestic gas. Bangladesh needs to engage with the donor agencies to provide specific credit support and guarantees to underpin the terminal construction and LNG supplies.

⁸⁷ ADB (2007) Page 17

⁸⁸ Energy Bangla (<http://www.energybangla.com/2013/04/18/2630.html#.UZDzm7VwpnI>) and Deloitte (http://www.psg.deloitte.com/newslicensingrounds_mm_130415.asp)

Overall Conclusions: Pakistan and Bangladesh

Bangladesh and Pakistan have been engulfed by a serious ongoing energy crisis which if not tackled will damage further their economic prospects. From booming cheap gas-fuelled economies both countries are now struggling to supply energy to a minimum standard required for the basic functioning of the population.

A combination of subsidies for power and gas end-users, high levels of electricity and gas losses, and lack of attractive fiscal terms for domestic gas have not only diminished the availability of gas supplies but also caused heavy budgetary losses due to the importation of expensive liquid fuels. It also hampered the capability of their national gas and power companies to increase the supply of natural gas due to the constant squeezing of their balance sheets because of subsidies and government take.

There are also major E&P challenges, such as the decreasing trend in the size of undeveloped gas fields, lack of geological information for unconventional and frontier areas and limited technology and skilled human resource availability.

On the domestic front, it is of utmost importance to increase domestic production which offers the cheapest energy alternative when compared to liquid fuels or LNG. After being accustomed to very cheap gas on one hand both countries now struggle with the notion of paying attractive well-head prices to increase domestic gas production and don't accept that they will need to pay market prices for LNG. On the other hand they need to increasingly pay higher prices for imported liquid fuels in order to provide electricity and fuels to their industries and population in general.

In the case of Bangladesh the annual bill of \$2.2 billion in power and fuel subsidies could be used to explore for gas or build 2,000 MW of power capacity. In the case of Pakistan, the \$5 billion subsidy to the power sector would be enough to fund OGDC/PPL equity shareholding in deep water or tight gas blocks or to fund Pakistan's contribution to the TAPI Pipeline.

Both countries have enhanced their fiscal terms and have recently launched license rounds for gas and oil exploration. Without taking into account other factors such as bonuses and royalties, the gas prices offered by Pakistan look more attractive than the prices offered by Bangladesh, which are slightly above India's 2009 formula price for KG basin D6 block, which the producers claim are insufficient to allow for investment in deepwater exploration – they are asking for prices north of \$8/MMBtu to drill new development wells.

Figure 38: Comparative E&P prices for India, Pakistan and Bangladesh

Source: Author estimate based on MPNR, Petrobangla & Kanani (2011)

In both countries the revised E&P Policy still hinders the ability of producers to directly access the end user market, either by imposing a 40% windfall tax in the case of Pakistan or by the first right of refusal granted to Petrobangla, in the case of Bangladesh.

To allow for LNG imports, Pakistan and Bangladesh need to empower a strong project sponsor, allow for more flexibility in terms of contracting spot and short/medium term LNG supplies, guarantee terminal and regas capacity payments, and attract multilateral agencies or the IFC as equity investors and providers of appropriate guarantees to LNG sellers.

It is also fundamental for both countries to review domestic energy pricing to accommodate more expensive LNG – which indeed is still cheaper than imported diesel and HSFO. Price reform, coupled to more attractive fiscal regimes for domestic gas will be a key factor to attract private investors to explore for and develop domestic gas.

Imported gas prices appear to be \$11.9-13.0/MMBtu at the border for the pipeline projects and \$17-18/MMBtu for regasified LNG⁸⁹. However with current end-user prices at \$1.08-7.5/MMBtu in Pakistan and \$0.90-3.37/MMBtu in Bangladesh the only way to accommodate imported supplies is pooling with domestic gas either for the entire country or for the power sector alone.

The import of higher-priced gas should be followed by pricing reform as the national budgets will not be able to afford subsidies for a much prolonged period. The way forward for both countries is to offer an attractive fiscal regime to boost exploration and drilling of domestic gas -

⁸⁹ Crude @ \$100/MMBtu.

it would be much cheaper than LNG. Pakistan has made considerable progress in improving fiscal terms for E&P but it needs yet to foster offshore exploration which is still in a very nascent stage.

Both countries should also develop a better understanding of the potential for unconventional gas. Pakistan has made some progress in devising policies for tight and shale gas, but Bangladesh is still lagging behind.

In addition to guaranteeing security of supply it is important to also find the “hidden” gas in the system, by reducing gas and power losses and improving the efficiency in power generation, by replacing inefficient fuel oil fired power plants with combined cycle power generation.

The losses in Pakistan’s gas system are deemed to be equivalent to 10% of the sales gas volume, or 4 Bcma. If losses were reduced to 2%, which is the internationally accepted standard, this would save 3.2 Bcma which could fuel 2,500 MW of combined cycle power plant and save around \$1.5 billion/year on imported fuel costs. Although gas losses in Bangladesh are reported to be below 5%, the power losses are extremely high, accounting for 15% in the fiscal year ending in 2012.

Pakistan and Bangladesh have yet to complete the reform of the gas sector. Although some degree of unbundling has been achieved, a few key changes are needed to provide more competitiveness and transparency, such as:

- Allow producers to access end-users and transform the existing T&D companies into real utilities, earning appropriate distribution/transportation margins. This can only be fully achieved with the end of cross-subsidies between consumer segments.
- Ensure a proper power balance and independence for the regulatory agencies.
- Gradual price reform in such a way that end-user prices should not be set below the cost of supply.
- Provide for appropriate credit guarantees in gas and power supply agreements to mitigate default by large consumers as this is currently endangering the health of gas and power companies.

Pakistan and Bangladesh would also benefit from closer cooperation with India in energy matters. This would benefit all the countries involved by:

- Providing more compelling markets and credit robustness to anchor both the TAPI pipeline and a Myanmar-India pipeline (transiting Bangladesh) should Myanmar decide to significantly diversify its gas exports.
- Allowing Indian companies – which have a better grasp of the region’s risks - to invest in the Pakistan and Bangladesh upstream.
- Cooperating in cross-border electricity trade as a way to circumvent Pakistan and Bangladesh credit risk.
- Cooperating in gas/LNG swaps. For example India could develop LNG import terminals near the Pakistan/Bangladesh borders and export gas or electricity to both countries.
- The same could be achieved by the construction of coal-fired power plants in India to export electricity to Pakistan and Bangladesh.

Both countries need to also pay serious attention to developing their coal resources. Despite the low quality of domestic coal it may provide an alternative to imported fuel oil in the development of power generation clusters in the mining sites.

Appendices

Appendix 1: Summary features of Pakistan E&P 2012 exploration bid

Onshore blocks

- Royalty and tax regime.
- Royalty is payable @ 12.5% of the value of petroleum produced and saved.
- Corporate income tax at 40% of profits and gains with royalty payments allowed as expense item.
- In case of Joint ventures with foreign companies, local E&P companies including GHPL shall have working interest in full participation, as mentioned below:
 - o Zone I: 15%
 - o Zone II: 20%
 - o Zone III: 25%
- Production Bonuses:

Cumulative Production (mm BOE)	Bonus (\$)
At start of commercial production	600,000
30	1,200,000
60	2,000,000
80	5,000,000
100	7,000,000

- Minimum work programme: for the purpose of providing flexibility to the contractors in discharge of work obligations under the petroleum concession agreements, a new concept of work units has been developed which enables the petroleum right holder to finalize the Work programmes based on the best technical judgment as compared to the previous system of firm obligation of seismic coverage and number of wells.
- Import duties and sales tax are payable at 5% on the import of equipment not locally manufactured. The import duty is 10% for items locally manufactured other than wellhead on which import duty is 15%.
- No import duties, sales tax or license fee is applicable on machinery, equipment and materials imported or exported by the companies providing technical services to petroleum exploration and production companies.
- Training fee:
 - o \$25,000 per year - Exploration phase
 - o \$50,000 per year - Development and Production Phase
- Minimum expenditure on welfare projects: \$ 25,000/year during exploration phase and up to \$700,000/year during production phase
- Windfall Levy (WLO) applicable on crude oil and condensate according to the formula
 - o $WLO = 0.4 \times (M-R) \times (P-B)$

- WLO - Windfall Levy on crude oil and condensate;
- M - Net production (petroleum produced & saved);
- R - Royalty;
- P - Market Price of crude oil and condensate
- B- Base Price: The base price for crude oil and condensate will be \$40 per bbl.
The base price for crude and condensate will escalate each calendar year by \$0.5 per barrel starting from the date of first commercial production in contract area.
- The benefit of windfall levy may be equally divided between the Federal Government and Provincial Government. The ceiling would be reviewed as determined by the Government.
- Windfall levy for natural gas (WLG) will be applicable for sales to parties other than Government of Pakistan on the difference between the applicable Zone price and the 3rd party sale price using the formula:
 - $WLG = 0.4 \times (PG - BR) \times V$
 - WLG - Windfall Levy on share of natural gas;
 - PG - Third Party Sale Price of natural gas;
 - BR - Base Price;
 - V - Volume of gas sold to third party excluding royalty.
 - The Base Price will be the applicable Zone price for sale to GOP as outlined in section IV (10) below. Where the 3rd party sale price of gas is less or equal to the base price, the windfall shall be zero. The windfall levy shall not apply on sales of natural gas made to Government of Pakistan and the Provincial Government.
- Crude oil price.
 - The Producer Policy Price for crude oil delivered at the nearest refinery gate shall be equal to C&F price of a comparable crude oil or a basket of Arabian/Persian Gulf crude oils (Reference Crude or RC) plus or minus a quality differential between the RC and the local crude oil. No other adjustment or discount will apply other than Windfall Levy. C&F price will be arrived at on the basis of FOB price of imported crude oils into Pakistan plus freight on AFRA, which is deemed chartered rate.
- Gas price
 - For all gas pricing, a Reference Crude Price (RCP) equal to the C&F price of a basket of Arabian/Persian Gulf Crude Oils imported in Pakistan during the first six months period of the seven months period immediately preceding the relevant price notification period (Import Basket) as published in an internationally recognized publication acceptable to the parties will be used. C&F price will be arrived at on the basis of FOB price of imported crude oils into Pakistan plus freight on AFRA, which is deemed chartered rate.
 - The gas price will be calculated according to the following formula:
- $P_g = P_m \times D_z / C_f$, where
- Where P_g is the Gas Price in \$/MMBtu
 - D_z is the zone index which shall have the value of:
 - 63.33% for onshore blocks;
 - 73.88% for Offshore shallow;
 - 84.44% for Offshore Deep and;
 - 95% for Offshore ultra-deep.

- Cf is the Applicable Conversion Factor, the weighted average of the heating values expressed in MMBtu per barrel for the basket of Arabian/Persian Gulf Crude Oils imported in Pakistan.
- Applicable Marker Price in \$ per barrel determined as follows:
 - When RCP is up to \$30/barrel, Pm equals \$30/barrel;
 - When RCP is higher than \$30/barrel and below \$50/barrel, Pm equals 30 plus 50% of the incremental RCP above \$30/barrel;
 - When RCP is higher than \$50/barrel and below \$70/barrel, Pm equals 40 plus 30% of the incremental RCP above \$50/barrel;
 - When RCP is higher than \$70/barrel and not over \$110/barrel, Pm equals 46 plus 20% of the incremental RCP above \$70/barrel;
 - When RCP is higher than \$110/barrel, Pm equals \$54/barrel
 - The RCP ceiling of \$110/barrel would be reviewed after every five years or as and when the pricing dynamics significantly change in the international market.
- Transmission tariff
 - E & P companies are allowed transmission tariff for the gas pipeline connecting the field gate to the main transmission system, if such system is constructed and operated by them.
- Exploration period
 - Consists of an initial term of 5 years comprising Phase-I of three years and Phase-II of two years together with two subsequent renewals of two-years each, for a total period of 9 years.
- Retention period
 - Maximum of up to 5 years is allowed on a case by case basis to enable the companies to evaluate commercial aspects of the discovery and to make market arrangements for disposal of discovered gas.
- Lease term: 25 years
- Relinquishment: the companies are required to relinquish 30% of the Licence Area at the end of Phase-I of the initial Term, 20% of the remaining area at end of Phase-II of the initial Term and 10% of the remaining Licence Area prior to the termination of the first renewal.

Offshore blocks

- Fiscal Regime: Production Share Contract.
- Royalties: from zero to 12.5% depending upon the production phase.
- Corporate income tax is capped at 40% of profits and gains with royalty payments allowed as tax expense item.
- Depreciation rates:
 - On successful exploration and development wells 33% on Straight Line.
 - On dry holes (exploratory wells) will be expensed immediately upon commencement of commercial production or relinquishment whichever is earlier.
 - Non-commercial well (exploration wells) expensed upon relinquishment of license
 - On facilities and offshore platforms 20% Declining Balance. (Carry forward of any unabsorbed depreciation until such depreciation is fully absorbed)

- Government participation through profit share on sliding production scale instead of direct Government participation
- Government representative in PSC will be Government Holdings Pakistan Limited (GHPL) who will be granted the Exploration Licence and Development and Production Lease. The Contractor will initially receive the profit oil and profit gas shares and will be responsible for the management of the production sharing agreements.
- Costs: The Contractor can recover 100% of the costs up to a limit of 85% of the gross revenues. Royalties of 12.5% are included in cost recovery.
- Contractor profit share: depends on volume and offshore zoning. Minimum is 20% for shallower blocks and volumes above cumulative production of 1,200 million BOE and maximum is 95% for ultra-deep blocks with cumulative production of 0-300 million BOE.
- Production bonus: \$600,000 to \$7,000,000 per annum depending upon volumes range.
- Gas Transmission Pipeline: The first pipeline connecting a field to onshore gas transmission system is allowed as cost recoverable, if such system is constructed and operated by the E&P Companies.
- Exploration Period: initial term of 5 years and two subsequent renewals of one-year each, for a total exploration period of 7 years.
- Retention Period: a maximum retention period of up to 10 years in case of a Commercial Discovery is allowed on a case by case basis to enable the companies to evaluate commercial aspects of the discovery and to make market arrangements for disposal of discovered gas.
- Total lease term: Initial term of 25 years based on production profile plus one possible renewal of 5 years.

Appendix 2: Key features of Bangladesh's E&P 2012-2013 bid

- Exploration Period: 7 years for onshore and 8 years for offshore blocks
- Operator can elect to pursue geological and geophysical surveys only for a 3-year period, after which if they want to continue with exploration they shall commit to drill a well in the remaining 2 years of the exploration period
- Term: 20 and 25 years after Petrobangla approval of the Development Plan for oil and gas respectively, extendable for another 5 years
- In addition to biddable Work Programme, the Mandatory Work Programme consists of 2D seismic and one exploration well
- Employment of Bangladeshi nationals: minimum of 20% in the Exploration Period, rising to 90% after 10 years of production
- Maximum annual cost recovery: 55% of the revenues per Calendar Year
- Biddable profit share on a sliding scale, from 5,000 to above 100,000 barrels/day for oil and 75 to above 600 mmcf/d for gas
- Petrobangla can take its share in cash or in kind
- Associated gas priority use in enhancing oil production
- Contractor can dispose of gas freely but Petrobangla has first right of refusal
- Contractor shall pay 4% of their revenues to pay Petrobangla for taxes and fees associated to deliver gas to market place

- Gas prices for Petrobangla and affiliates carry an additional discount of 1%
- Invoices paid after 60 days of receipt
- Contractor has the right to build cost recoverable pipeline to transport oil and gas to markets.
- Bonus payable to Petrobangla: from \$500,000 for production up to 75 mmcfd to \$6 million for volumes in excess of 600 mmcfd.
- Research and development fee of \$0.04/cu ft.
- Other fees payable to Petrobangla: \$200,000/year during Exploration and Development phase and \$300,000 during Production phase, cost recoverable
- Gas Prices:
 - Onshore: 75% of Marker Price
 - Onshore western: 90% of Marker Price
 - Offshore: 100% of Marker Price
- Marker Price is the Arithmetic Average Asian Petroleum Price Index for High Sulphur Oil 180 CST FOB Singapore
 - Price floor is \$100/tonne. Price ceiling is \$200/tonne
 - The floor and ceiling prices for the previous PSC were respectively \$70 and \$180/tonne.
- Special package of conditions for Kutubdia and Teknaf blocks: operator entitled to an additional 5% of the gas produced to Petrobangla, on top its regular profit-sharing.
- Carried interest stake of 10% in all the shallow water gas blocks for Bangladesh Petroleum Exploration Company (Bapex).
- Full repatriation of profits
- Obligation to sell gas in the domestic market. Exports will not be allowed (the previous PSC allowed the export of LNG but not of pipeline gas to prevent exports to India).

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Notes

Exchange rates

1 \$ = 97.25 Pakistani Rupees on 28/12/2012

Average exchange rate January 2012: 90.21 Rs/\$

1 \$ = 79.83 Bangladeshi Taka on 28/12/2012

Average exchange rate January 2012: 83.0137 Tk/\$

Acronyms of Companies' Names and Abbreviations

ADB – Asia Development Bank

APSCL – Ashuganj Power Station Company, Bangladesh

ARSESP – Agencia Reguladora de Saneamento e Energia do Estado de Sao Paulo

BAPEX - Bangladesh Petroleum Exploration & Production Company Limited

BERC - Bangladesh Energy Regulatory Commission

BPC – Bangladesh Petroleum Corporation

BGFCL - Bangladesh Gas Fields Company Limited

BGSL - Bakhrabad Gas Systems Limited

BPDB – Bangladesh Power Development Board

CNG – Compressed Natural Gas

D&P – Development and Production

DSME – Daewoo Shipbuilding & Marine Engineering Co.

ECC – Economic Coordination Committee, Pakistan

EGCB - Electricity Generation Company of Bangladesh

ENGRO – Engro Corporation, Pakistan

EPTL – Elengy Project Terminal Ltd

E&P – Exploration and Production

FSRU – Floating Storage and Regasification Unit

FOTCO - Fauji Oil Terminal & Distribution Company Ltd

GDS – Gas Development Surcharge

GEI - Global Energy Group

GOP – Government of Pakistan

GTCL - Gas Transmission Company Ltd

HDIP - Hydrocarbon Development Institute of Pakistan

HSFO – High Sulphur Fuel Oil

IEA – International Energy Agency

IOC – International Oil Companies

ISGS – Inter State Gas Systems Ltd

JGTDL - Jalalabad Gas T & D System Ltd.

LNG – Liquefied Natural Gas

MGCL - Mari Petroleum Company Limited, Pakistan

MOU – Memorandum of Understanding

MPNR – Ministry of Petroleum and Natural Resources, Pakistan

NTPC – National Transmission and Power Company, India

NWPGCL - North West Power Generation Company Ltd, Bangladesh

OGDCL – Oil and Gas Development Company Ltd, Pakistan

OGRA – Oil and Gas Regulatory Agency, Pakistan

O&M – Operation & Maintenance

Pak-Iem – Pakistan Integrated Energy Model

PGP - Pakistan GasPort Ltd

PGCL - Pashchimanchal Gas Company Ltd.

PEPCO – Pakistan Electric Power Company
PIP – Petroleum Institute of Pakistan
PPL – Pakistan Petroleum Ltd
PQA – Port Qasim Authority
PSO – Pakistan State Oil
REB – Rural Electrification Board, Bangladesh
RLNG – Regasified Liquefied Natural Gas
RPCL – Rural Power Company Ltd.
RPGCL - Rupantarita Pakritik Gas Company Ltd
SIPA – Sindh Environment Protection Agency
SGFL - Sylhet Gas Fields Company Ltd
SIPP - Social Investment Program Project
SNGPL – Sui Northern Gas & Pipeline Company
SSGC – Sui Southern Gas Company Ltd
TCC – Tianchen Corporation China
TGTDCL -Titas Gas Transmission and Distribution Company Ltd
T&D – Transmission and Distribution
UEPL -United Energy Pakistan Limited
UK DECC – UK Department of Energy and Climate Change
WZPDCL - West Zone Power Distribution Company Ltd.