CHAPTER-4
ENERGY SCENARIO IN ASIA

4.1 INTRODUCTION

Central Asia is one of the pivotal regions of the world. It is located at the core of the Eurasian continental space and represents a critical connection between the large and dynamic continental economies – China, the European Union, India, Japan and Russia. The Central Asian countries with their large natural and human resources face both an opportunity and a challenge as the Eurasian economic space is now rapidly integrating.

Gas with its inherent environment-friendly nature is assuming greater significance. Gas consumption could rise by 2.7 percent year-by-year for the next twelve years. During this time, Asia will be the fastest growing consumption market as it witnesses rapid economic growth.

4.2 ASIAN CONSUMPTION MARKET

Energy and energy infrastructure will play a critical role in shaping the economic destiny of Asia. It is well recognized that accelerated economic growth and subsequent industrialization have boosted the region's demand for all energy resources.

Analyses suggest that gas consumption in Asia will rise from approximately 340 BCM in 2005 to about 785 BCM in 2020, growing at 5.8 percent year-by-year.

If current indigenous production levels are maintained and all signed contracts are honored, Asia could have a gas deficit of 415 BCM by 2020. Hence, the region has to significantly increase its indigenous production and secure adequate LNG through cross border pipeline.

Despite the structural differences in various Asian countries – Japan, Korea, China and India will compete fiercely for LNG and piped gas supplies. It is therefore necessary to understand how the region's heterogeneous economies are likely to respond in the short to medium term flow constrained environment and their subsequent impact on the global gas market. *[McKinsey Report]*

- **Japan & Korea:** Short resource countries like Japan and Korea have traditionally relied heavily on long term LNG contracts to meet domestic demand. As a result, both countries will aggressively try to renew expiring contracts, albeit at higher prices. This trend has been observed in recently negotiated contracts.

- **China:** China has access to enormous coal reserves. Yet it would be the highest natural gas consumer in the world with a consumption growth rate of 2.7 percent during the next twelve years, or a compounded rate of around 10.4 percent as compared to world gas consumption. In real terms, consumption will rise from 45 BCM in 2005 to about 200 BCM by 2020, thereby increasing the share of natural gas in the country's energy mix from 3 percent to 7 percent.

- **India:** Gas consumption in India has grown at 8 percent from 1997 to 2007. Consequently, India's share in the Asian consumption mix has risen from 8.6 percent to 10.1 percent in the last decade. In 2007, India was the third largest natural gas consumer in Asia with an annual consumption of 45 BCM. Looking ahead, demand for natural gas will come from various sectors like fertilizer producers, city gas distributors, industrial gas distributors and peaking power producers amongst others. The analyses suggest that India's total demand could be 115 to 135 BCM by 2020. Recent gas finds along with the fact that only 20 percent of India's sedimentary basins have been relatively well explored, instill confidence that indigenous gas could play an important role in the short to medium term. For this, the country needs to significantly accelerate its exploration and production efforts. Further, India should also prioritize the construction of international cross-border pipelines.

- **ASEAN Countries:** In Asia the two largest exporters – Malaysia and Indonesia - have substantial gas reserves. But growing domestic demand, stagnating production, and investment delays are constraining their export potential. Indonesia expects domestic consumption to rise from 46 percent of the total volume of indigenous gas to 70 percent by 2010. This, coupled with the Malaysian government's drive to promote the use of clean fuels for domestic purposes, will boost consumption of indigenous gas. These shifts in consumption patterns will reduce global supply by 10 to 15 BCM in the medium to long term, i.e. from 2015 to 2020.

4.3 COUNTRY-WISE DEMAND/ SUPPLY ANALYSIS

Asian countries have a tremendous potential to drive the economy of this region. The first step shall be to understand the gas supply and demand position of the Asian countries including resources.

In this research

- 20 years and 330 operating days has been taken as the life of gas reserve of a country to convert it into MMSCMD.

- 3 percent growth in cumulative rate of consumption and 5 percent growth in cumulative rate of production have been taken for that country.

- It is assumed that the rate of production per year can be raised to only 80 percent of the reserve.

- The difference of production and consumption is the net Export/ Import of that country.

- Surplus/ Deficit of gas of a country have been derived from the difference between available reserve and consumption in that year.

- The production, consumption, Export/ Import data for 2006 has been taken from "BP Statistics Review 2007".

4.3.1 IRAN

Iran holds the second largest proved natural gas reserves in the world with 26.63 trillion cubic meters at the beginning of 2005. This represents 15.5 percent of the world total. Iran shares the world's largest non-associated gas field - South Pars - with Qatar. Despite this prolific resource base, Iran has fallen short of neighbors Qatar and Oman in translating its gas into export revenues. In 2004 Iran exported just 2.91 billion cubic meters of gas, and that too to a single buyer - Turkey. This compares poorly as compared to neighboring Qatar's 23.66 BCM of LNG exports and the UAE's 7.38 BCM.

Exhibit 4.1 Iran

Iran is intent on developing its natural gas reserves and to catch up with Qatar before what it believes is more than Qatar's fair share of the shared North Field/Smith Pars reservoir. So far Qatar has produced around 20 percent of its share of the field's reserves compared to less than 1 percent by Iran.

- Iran is the most populated country of the Middle East. The oil and natural gas sector currently accounts for one-fifth of its GDP.
- Primary energy demand in Iran is projected to increase at an average annual rate of 2.6 percent in 2003-2030, down from around 5 percent over the past decade.

- Iran holds second largest natural gas reserves in the world, almost half of which is in the super giant south pars field. Gas production is projected to grow to 110 BCM in 2010 and 240 BCM in 2030.

- Iran has immense oil and gas reserves, but is not able to capitalize them as well as other countries, due to barriers in foreign investment and heavy subsidy. *[Energy Information Administration & World Energy Outlook 2007]*

Energy Policy

Foreign companies in Iran cannot participate directly in business activities, but have to look for affiliates. The government, however, accepts foreign investment needed to maintain current oil production levels. Iran also plans to diversify its economic base away from upstream i.e. oil and gas, to LNG and petrochemical projects among other projects.

Since 1960, Iran has been the second largest member of OPEC after Saudi Arabia. Its power sector is controlled by Tanvir; a state controlled company which has broken up into smaller companies in a process of privatization.

In the recent years, government has been concerned about the high growth in domestic energy consumption. It recognizes the need to reduce consumption so as to free the oil for export. The current priority of the government is to give energy efficient buildings, improve vehicle efficiency and use CNG as vehicular fuel.

Gas development in Iran is driven by four main end uses.

1. Gas will be used to stabilize oil products, or at least soften the decline in rates in mature onshore fields that have been as high as 200,000 b/d annum.

2. Iran, like most OPEC countries is promoting increased gas substitution for oil in the domestic market to free up oil for export.

3. Iran intends to use natural gas as a feed-stock to drive the expansion of the Petrochemical industry, with an aim to increase its nameplate ethylene capacity from around 700,000 metric tons in 2003 to more than 6.5 million tons in 2010.
4. Finally and the most important point for the proposed AGG, Iran intends to monetize its gas resources by exporting it east to India, and west to Europe as LNG, GIL or by pipeline.

Iran's push to fulfill its natural gas objectives requires billions of dollars in investment, much of which must come from foreign sources. As a means for bringing foreign oil and service company investment, Iran developed so-called "buy- back" contracts, a form of service contract lasting six to seven years at most, in which the contractor receives remuneration in the form of an allocated share of production. In the case of gas development, that repayment has thus far been in liquids.

While potential gas investors are insisting that the time frame for such contracts must be extended if LNG or other export options are introduced, in practice buy back contracts are being made increasingly more rigid, particularly in the areas of local content and participation requirements. NIOC prefers foreign companies joining a local firm in the bidding process - a policy adopted as a means of encouraging development of a domestic upstream industry.

Primary Energy Mix & Sectoral Analysis

Table 4.1 shows the distribution of growth in total primary energy demand in various sectors like Power, Industry, Transport and other sectors.

[Source: World Energy Outlook 2004]

IRAN								
	Energy Demand (MTOE)			Share (%)			Growth(% p.a)	
	2003	2020	2030	2003	2020	2030	2003-2020	2003-2030
Total primary energy demand	136	225	271	100	100	100	3	2.6
Coal	1	2	2	1	1	1	2.8	2.3
Oil	66	96	111	48	43	41	2.2	2
Gas	68	120	149	50	54	55	3.5	3
Nuclear	-	2	2	-	1	1	-	-
Hydro	1	2	3	1	1	1	5.4	3.7

Other renewable	1	2	5	1	1	2	6.8	7
Power Generation & Water Desalinations	33	56	66	100	100	100	3.2	2.6
Coal	-	-	-	-	-	-	-	-
Oil	6	7	6	19	13	10	1	0.1
Gas	26	44	54	78	79	81	3.2	2.8
Nuclear	-	2	3	3	4	4	5.4	3.7
Hydro	1	2	3	3	4	4	5.4	3.7
Other Renewable	0	1	2	0	1	3	37.3	27.2
Industry	27	42	51	100	100	100	2.6	2.4
Coal	1	1	1	2	2	2	2.8	2.3
Oil	10	12	13	37	28	25	1	1
Gas	13	22	27	48	52	54	3.2	2.8
Electricity	3	7	9	13	17	18	4.2	3.6
Other Renewable	0	0	0	1	1	1	3.6	3.1
Transport	30	52	65	100	100	100	3.2	2.8
Oil	30	52	64	100	100	99	3.2	2.8
Other fuels	0	0	0	1	1	1	3.6	3.1
Other Sectors	48	72	87	100	100	100	2.4	2.2
Coal	-	-	-	-	-	-	-	-
Oil	16	18	19	34	25	22	0.6	0.6
Gas	25	40	50	51	56	58	2.9	2.7
Electricity	7	12	15	14	17	18	3.6	3.1
Other Renewable	1	1	2	1	2	3	5.1	5.7
Electricity generation (TWH)	153	286	359	100	100	100	3.8	3.2
Coal	-	-	-	-	-	-	-	-
Oil	24	30	26	16	10	7	1.1	0.2
Gas	117	220	289	77	77	80	3.8	3.4
Nuclear	-	6	6	-	2	2	-	-
Hydro	11	27	30	7	9	8	5.4	3.7
Other Renewables	0	4	9	0	1	2	32.5	23.3

Table: 4.1 Iran- Sectoral Energy Analysis

Total Primary energy demand of Iran was 136 MTOE (Million tonnes of equivalents) in 2003. Primary energy has climbed steadily since the Iran-Iraq conflict; averaging 5.6 percent annual growth in 1989-2003.

Oil and Gas accounted for 98 percent of the primary energy demand in 2003. The remaining 2 percent was accounted mostly by renewable sources like hydro and coal. Oil accounted for 48 percent in the fuel mix in 2003, but began a downward trend from 1971, when it was having a share of 84 percent. This was due to the government policy of substituting oil by natural gas, in all sectors partly through subsidies. The share of natural gas in the fuel mix jumped from a mere 12 percent in 1971 to 50 percent in 2003.

Primary energy demand is projected to double to 270 MTOE in 2030. Growth is expected to be, most rapid from now to 2010 at 3.4 percent per year, and then it is projected to slow down to 2.7 percent per year in 2010-2020 as economic expansion slows down. Natural gas consumption is expected to grow strongly at 3 percent per year, boosting its share to 55 percent in 2030. The share of oil in primary demand will fall by 7 percent to 41 percent in 2030. However the contribution of renewable, coal and nuclear is expected to be marginal.

Iran's primary energy demand mix for 2006 is shown in Exhibit 4.2.

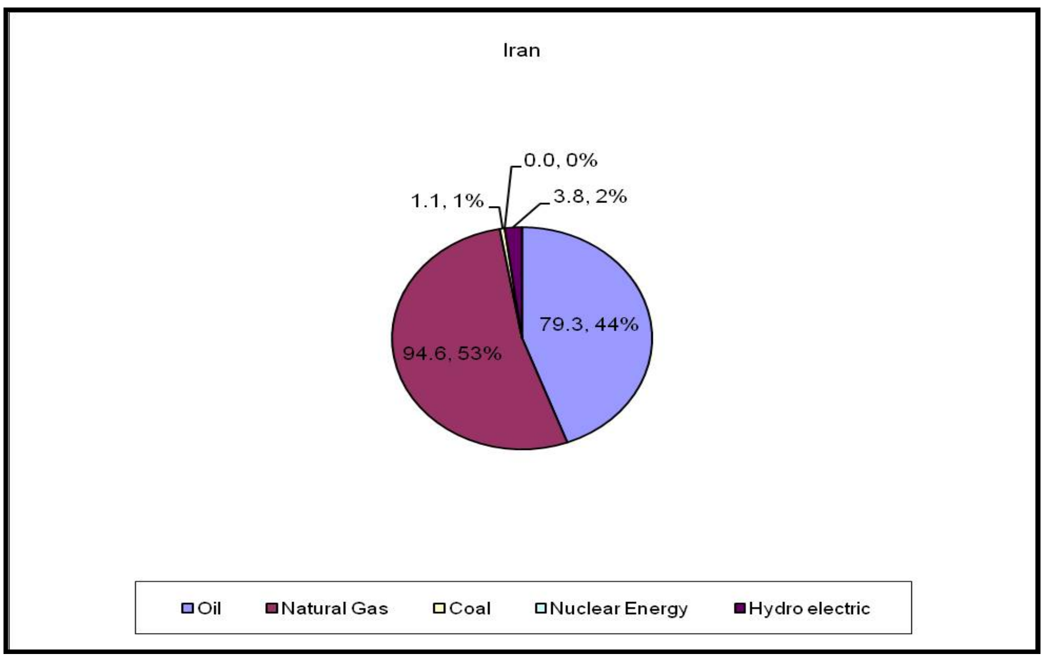

Exhibit: 4.2 Iran- Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves & Production

Key gas fields of Iran are presented in Table 4.2. Iran holds the world's second largest gas reserves, after Russia. *Cetigaz* estimates that Iran's proven reserves as on January 1, 2005 were 28 TCM, which is 16 percent of global gas reserves. Two thirds of the gas reserves are in non-associated gas fields. The country's largest gas field, the offshore South Pars gas field, is estimated to contain 13 TCM of natural gas and up to 4 billion barrels of condensate. North Pars is the second largest field in Iran with 1.4 TCM reserves.

Iran's total gas reserves have increased by 12 percent since 2000, mainly because of the re-evaluation of South Pars and discovery of several smaller fields. These include two major discoveries in 2000. TABNAK contains 850 BCM of natural gas and HAMA, while contains 133 BCM of the fuel.

Marketed production is projected to reach 110 BCM in 2010 and 240 BCM in 2030.

[Source: World Gas Handbook 2005-06]

S.No.	Location	Name	Comments
1	Mideast Gulf	South Pars	12.3 TCM, Twenty five phase development
2	Mideast Gulf	North Pars	3.6 Bcf/d
3	Fars Province	Aghar and Dalan	600 MMCF/d and 800 MMCF/d
4	Queshm Island	Gavarzin	25 MMCF/d
5	Southern Iran	Khangiran, Mazduran, Sarkhun	Produce non associated gas

Table:4.2 Iran- Key Gas Fields

In 2003, Iran was the net importer of gas to the tune of 2.3 BCM. It exported 3.5 BCM to Turkey but imported 5.7 BCM from Turkmenistan to meet the winter gas demands. Iran could export gas to Western Europe via Turkey. It has since started supplying gas to Turkey, Greece, Romania, Italy, and Austria. In 2004, Armenia and Iran constructed a gas pipeline that will deliver gas to Armenia for 20 years from 2007, with an initial flow of 5.5 BCM per year. Iran has also been discussing possible pipeline developments with Pakistan and India. It plans to become a net exporter by 2010, with net export of 5 BCM. These are the projects which will help Iran reach 31 BCM in 2010 and nearly 57 BCM in 2030, mostly in the form of LNG. Europe and Asia are expected to represent the main export markets for Iranian Gas.

Gas Surplus/ Deficit projection

The gas surplus/ deficit projection for Iran up to 2025 has been calculated based on the actual status of 2006 (*BP Statistics Review 2007*) on demand/ production and estimated reserve. The details calculated are shown in Table 4.3

Iran: (Reserve-4262 MMSCMD)[1]

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	319	358	416	482	559
Production	318	382	461	541	620
Export/Import	0	23	46	59	62
Surplus/deficit	3944	3904	3847	3780	3704

All Figs are in MMSCMD)

Table:4.3 Iran- Projection of Surplus/ Deficit of Gas

[1] *Note:*
20 years and 330 operating days have been taken as the life of a gas reserve. This is converted to the unit of MMSCMD from TCF/ TCM.

3 percent growth in cumulative rate of consumption has been considered.

5 percent growth in cumulative rate of production has been considered.

It is assumed that rate of production can be raised up to only 80 percent of reserve.

Difference of production & consumption is the net Export/ Import.

Surplus/ Deficit of gas is derived from difference of available reserve and consumption of particular year.

The status of actual production, consumption & export/ import for the year 1998 to 2004 is shown in Exhibit 4.3.

[BP Statistics Review 2007]

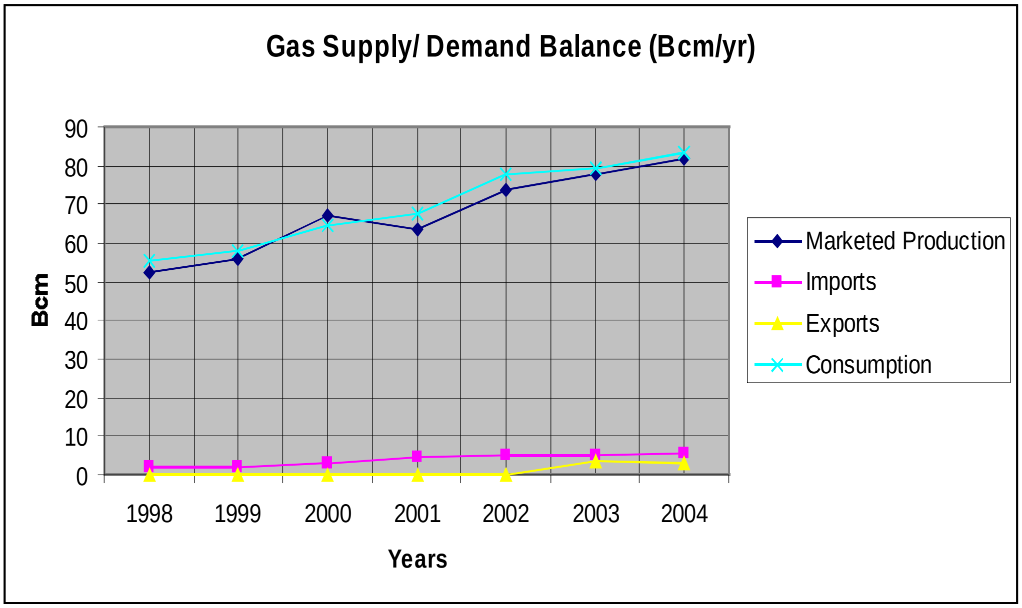

Exhibit: 4.3   Iran- Gas Supply/ Demand 1998-2004

4.3.2 BANGLADESH

Bangladesh has more than 16 trillion cubic feet (464 billion cubic meters) of gas reserves. Its proximity to India gives it potential to become a major player in the South Asian gas market. Domestic consumption of only some 957 million cubic feet per day (9.9 BCM) in 2001 appears to leave ample scope for exports to neighboring gas-thirsty India. Unocal and Royal Dutch/Shell have each proposed building a pipeline to take Bangladesh gas to India. In 2005 Bangladesh's real gross domestic product (GDP) grew at 5.4 percent, somewhat lower than the 2004 growth rate of 6.3 percent. Bangladesh, however, remains one of the world's poorest and most densely populated countries, and faces a number of obstacles to further growth and development. Bangladesh is a member of the South Asian Association for Regional Cooperation (SAARC), along with Bhutan, India, Maldives, Nepal, Pakistan and Sri Lanka. SAARC aims to promote regional economic cooperation as well as economic and social development in South Asia. In 2004, the seven SAARC members agreed to create a South Asian Free Trade Area (SAFTA), which came into force on 1January 2006. SAFTA aims to reduce tariffs and other trade barriers between the member countries.

Exhibit: 4.4 Bangladesh

Energy Policy

The overriding issue for Bangladesh's energy planners is whether to export gas to the huge market in India. The major political parties are officially committed to considering gas exports only if Bangladesh has proven reserves sufficient to cover 50 years of domestic demand. Despite the Norwegian Petroleum Directorate's study that suggests Bangladesh has enough gas to meet its needs for well over 150 years. The size of the country's gas reserves remains uncertain, particularly in relation to variable future domestic demand projections. Under pressure from the World Bank and from foreign producers in the country, the government had by autumn 2002 quietly come around to a position favoring exports to India. However the opposition continued to argue that no gas should be exported until a formal decision is made that a 50-year supply is better assured. Foreign oil companies are pulling back from exploration commitments, arguing that they cannot recover their costs unless they are allowed to sell gas to India since the domestic market is fully supplied. Both Unocal and Shell have refused to invest any more unless the government allows gas exports. In October 2001 Unocal submitted to Petrobangla a gas export pipeline proposal known as the Bangladesh Natural Gas Pipeline Project. This proposal called for construction of a 30-inch 1,363 kilometer pipeline from its Bibiyanah gas field to the Delhi region. It proposed an initial capacity of 500 MMCF/d for start-up of commercial operations in mid-2005

Talks within the government were for initial exports of around 280 MMCF-350 MMCF/d (9 million cubic meters - 10 MMCM/d), which would later be increased to 500 MMCF/d. While the debate rages over exports to India, the government is more clearly receptive to the idea of playing a regional transit role. In July 2002, Bangladesh's Ministry of Energy and Mineral Resources said that the country would consider proposals for the construction of a pipeline to allow the transit of gas from Myanmar (Burma) to India through its territory. An expert committee was set up to assess the viability of the $2.5 billion proposal.

To encourage natural gas exploration, the government opened the natural gas sector to foreign investment in 1993, after initiating the First Bidding Round of Production Sharing Contracts. Currently, foreign companies produce 501 MMCF/d of natural gas from four gas fields. The leading foreign producer is Chevron, which produces 331 MMCF/d from the Jalalabad and Moulavibazar fields. Chevron also expects to begin producing an estimated 300 MMCF/d of natural gas from the Bibiana field in October 2006. The UK's Cairn Energy is the second largest foreign natural gas production company in Bangladesh. It produces 146 MMCF/d of natural gas from the country's lone offshore gas field at Sangu. Canada's Niko Resources has been involved in disputes with the government after two blowouts that occurred in 2005 at the company's Chattak (formerly known as Tengratila) gas field.

Primary Energy Mix

Primary energy demand mix for Bangladesh in 2006 is shown in Exhibit 4.5. Natural gas consumption has the largest share of 74 percent in primary energy consumption, followed by oil consumption at 22 percent.

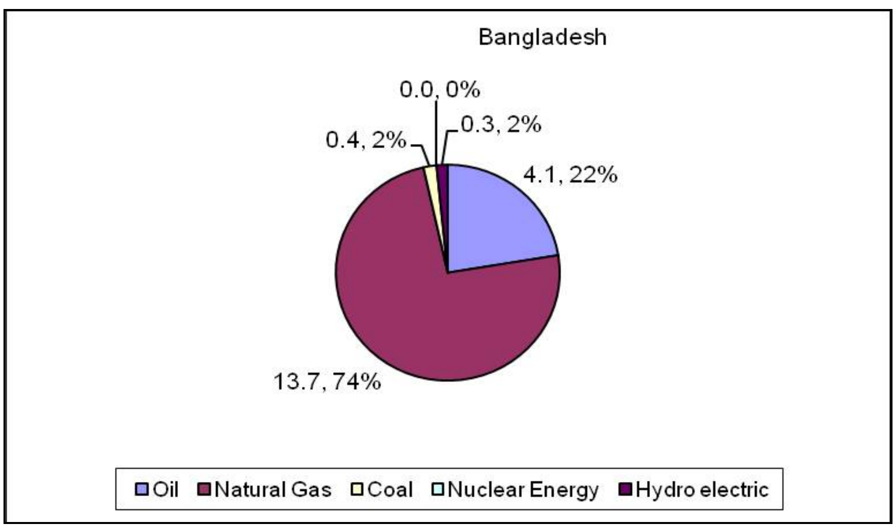

Exhibit: 4.5 Bangladesh- Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves and Production

Natural gas reserve estimates vary widely for Bangladesh. Oil & Gas Journal (OGJ) reported that Bangladesh had 5 trillion cubic feet (TCF) of proven natural gas reserves as of January 2006. This is significantly down from OGJ's January 2005 estimate of 10.6 TCF. It is not clear why the large downgrade of

Bangladesh’s natural gas reserves occurred. In mid-2004, estimates from state owned Petrobangla put net proven reserves at 15.3 TCF. Bangladesh’s Ministry of Finance estimated in 2004 that the country holds 28.4 TCF of total gas reserves, of which 20.5 TCF is recoverable. In June 2001, the U.S. Geological Survey estimated that Bangladesh contains 32.1 TCF of additional undiscovered reserves. While estimates of the country’s reserves vary, natural gas is Bangladesh’s only significant source of commercial energy. The government of Bangladesh estimates that natural gas accounts for 80 percent of the country’s commercial energy consumption. In 2004, Bangladesh produced 463 billion cubic feet (BCF) of natural gas, up from 429 BCF in 2003 and more than double the 1994 level. Despite increasing production levels, Bangladesh has never been a net exporter of natural gas. Given the uncertain size of the country’s natural gas reserves, the government has been reluctant to export natural gas and has instead focused on meeting current and future domestic energy needs. The key gas fields of Bangladesh are shown in Table 4.4.

[Source: World Gas Handbook 2005-06]

S.No.	Location	Name	Comments
1	Block 12, Northeast Bangladesh	Titas	Estimated remaining reserves: 81.19 BCM
2	Block 12, Northeast Bangladesh	Habiganj	Estimated remaining reserves: 76.13 BCM
3	Block 12, Northeast Bangladesh	Bibiyana	Estimated remaining reserves: 67.94 BCM
4	Block 12, Northeast Bangladesh	Kailas Tila	Estimated remaining reserves: 44.65 BCM
5	Block 12, Northeast Bangladesh	Rashidpur	Estimated remaining reserves: 30.39 BCM
6	Block 12, Northeast Bangladesh	Jalalabad	Estimated remaining reserves: 18.08 BCM
7	Block 16, Southern Bangladesh	Sangu	Estimated remaining reserves: 16.15 BCM

Table:4.4 Bangladesh- Key Gas Fields

Gas Surplus/ Deficit projection

The gas surplus/ deficit projection for Bangladesh up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. The details calculated are shown in Table 4.5

BANGLADESH (Reserve-67 MMSCMD)

Year	2006	2010	2015	2020	2025
Demand	46	52	60	70	81
Production	46	53	53	53	53
Export/Import	0	1	-7	-16	-28
Surplus/deficit	21	15	7	-3	-14

(All Figs are in MMSCMD)

Table:4.5 Bangladesh- Projection of Surplus/ Deficit of Gas

The status of actual production, consumption & export/ import for the year 1998 to 2004 is shown in Exhibit 4.6.

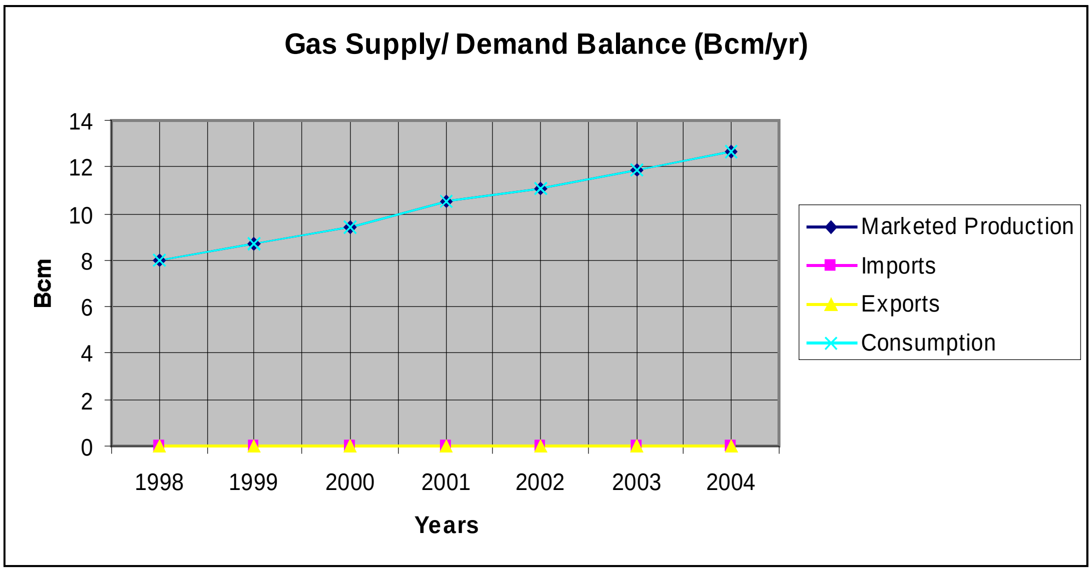

Exhibit: 4.6 Bangladesh- Gas Supply/ Demand 1998-2004

4.3.3 CHINA

China is the world's most populous country and has a rapidly growing economy. China’s real gross domestic product (GDP) is estimated to have grown at 9.9 percent in 2005, down slightly from the 2004 rate of 10.1 percent. Economic forecasts remain strong for China, with real GDP expected to increase 9.9 percent in 2006. China’s gas industry is still a relatively small and largely domestic affair. The country produced and consumed 2.93 million cubic feet of gas per day (30.3 billion cubic meters) in 2001, out of proved reserves of some 55 trillion cubic feet (1.56 trillion cubic meters). Most of the gas is produced either onshore in the south-western Sichuan Basin or north-central Ordos Basin by state owned PetroChina or offshore in the East and South China Seas by state China National Offshore Oil Corporation (CNOOC). The only foreign company currently operating a Chinese gas field is BP, which inherited the Yacheiig South China Sea field that feeds Hong Kong with its takeover of Arco. However, the field is soon slated to revert back to CNOOC, as it exercises a legal right to take its stake to 51% in all offshore fields. China has set out on an ambitious program to feed growing demand and displace more heavily polluting coal and expensive imported oil with a combination of expanded domestic gas production, LNG, and possibly pipeline gas imported from Russia.

The transport infrastructure to move the gas around the country and within cities is still at a very preliminary stage. The power plants and other facilities that would use the gas, and the necessary regulatory market mechanisms have yet to be fully developed.

Exhibit: 4.7 China

Energy Policy

Legal and fiscal terms to encourage foreign investors are not yet well defined. Price of gas is subsidized and do not reflect cost. And while the government is working with the World Bank and with inputs from foreign oil companies in an effort to develop a comprehensive regulatory code, it is likely to take two to three years before it becomes law. Nonetheless, companies appear willing to proceed with investments. China's State Council, the highest level of government, is responsible for the oil and gas industry. The State Development Planning Commission, formerly the State Planning Commission, draws up five-year plans that cover the energy industry, and monitors projects. State companies continue to dominate upstream gas in China. A guaranteed right to take a 51 percent share of any commercial gas discovery belongs onshore to PetroChina - the manifestation of China National Petroleum Corporation (CNPC). This is traded on overseas stock exchanges and offshore to CNOOC.

PetroChina is also responsible for gas pipeline infrastructure, including the huge West-to-East pipeline project and potential pipeline imports. Under the terms of the 1998 split-up of China's state sector into integrated units, CNOOC has the rights to handle LNG imports,. CNOOC's core upstream business is handled by separate regional subsidiaries that cover the Bohai Gulf, East China Sea, Nanhai East and Nanhai West. Other firms that were originally part of CNOOC now operate independently. Chinese estimates of the country's ultimate gas potential are substantially larger than internationally accepted figures for proved reserves.

Primary Energy Mix and Sector Analysis

Table 4.6 shows the distribution of growth in total primary energy demand in various sectors like power, industry, transport besides other sectors.

[Source: World Energy Outlook 2004]

CHINA								
	Energy Demand (MTOE)			Share (%)			Growth(% p.a)	
	2005	2015	2030	2005	2015	2030	2005-2015	2005-2030
Total primary energy demand	1742	2851	3819	100	100	100	5.1	3.2
Coal	1094	1869	2399	63	66	63	5.5	3.2
Oil	327	543	808	19	19	21	5.2	3.7
Gas	42	109	199	2	4	5	10	6.4
Nuclear	14	32	67	1	1	2	8.8	6.5
Hydro	34	62	86	2	2	2	6.1	3.8
Biomass & waste	227	225	227	13	8	6	-0.1	0
Other Renewables	3	12	33	0	0	1	14.4	9.9
Power generation	682	1222	1774	100	100	100	6	3.9
Coal	605	1073	1487	89	88	84	5.9	3.7
Oil	18	18	15	3	1	1	0	-0.8
Gas	7	25	64	1	2	4	13.8	9.4
Nuclear	14	32	67	2	3	4	8.8	6.5

Hydro	34	62	86	5	5	5	6.1	3.8
Biomass & waste	3	6	38	0	1	2	6.7	10.2
Other Renewables	0	6	17	0	0	1	36.5	18.4
Industry	478	833	1046	100	100	100	4.8	3
Coal	373	573	605	33	32	25	4.4	1.9
oil	39	52	57	8	6	5	3.1	1.5
Gas	12	30	48	3	4	5	9.3	5.5
Electricity	117	262	395	24	32	38	8.5	5
Heat	29	44	51	6	5	5	4.2	2.2
Biomass & waste	1	2	22	0	0	2	5.5	13.6
Other Renewables	0	0	0	0	0	0	-	-
Transport								
oil	115	231	442	95	96	96	7.2	5.5
Biofuel	1	2	8	0	1	2	11.6	11.7
Other fuels	6	7	9	5	3	2	2.3	1.9
Residential, services & agriculture	421	540	642	100	100	100	2.5	1.7
Coal	64	70	63	15	13	10	1	0
oil	62	95	123	15	18	19	4.4	2.8
Gas	13	32	59	3	6	9	9.7	6.3
Electricity	45	94	182	11	17	28	7.6	5.7
Heat	13	27	41	3	5	6	7.5	4.6
Biomass & waste	222	215	159	53	40	25	-0.3	-1.3
Other Renewables	3	6	16	1	1	2	8.2	7.1
Electricity generation (TWH)	2544	5391	8472	100	100	100	7.8	4.9
Coal	1996	4326	6586	78	80	78	8	4.9
oil	61	5849	2	1	1	-0.5	-0.9	
Gas	26	98	313	1	2	4	14.2	10.5
Nuclear	53	123	256	2	2	3	8.8	6.5
Hydro	397	717	1005	16	13	12	6.1	3.8
Biomass & waste	8	17	110	0	0	1	7.7	10.9
Other Renewables	2	51	153	0	1	2	36.1	45.5

Table: 4.6 China- Sectoral Energy Analysis

Power sector hold 39.1 percent of the total energy demand. Coal is an important fuel for power generation, but substitution by gas is increasing year by year. (from 0.01 to 0.02 percent). Chinese gas consumption which was just 40 BCM in 2004, is projected to increase more than fivefold in the next decade

Industrial sector holds 27.1 percent of the total energy demand. Coal plays an important role as fuel for industries with 78 percent usage, as compared to other substitutes like oil and gas. However, gas is expected replace coal in the future.

Residential, services and agriculture sector hold 24.1 percent of the total energy demand. Coal and oil are important fuels with energy consumption of 64 MTOE and 62 MTOE. However, gas with current growth rate of 9.1 percent as compared to 15 and 4.4 percent of coal and oil will replace both these fuels.

Oil is an important and dominating fuel of the transport sector with energy consumption of 115 MTOE, and it will increases at a growth rate of 7.2 percent. The growth rate of bio-fuel is also good at 11.2 percent, but no where close to oil. In the future too, oil is projected to remain the main fuel in China's transport sector.

China's primary energy demand mix for 2006 is shown in Exhibit 4.8.

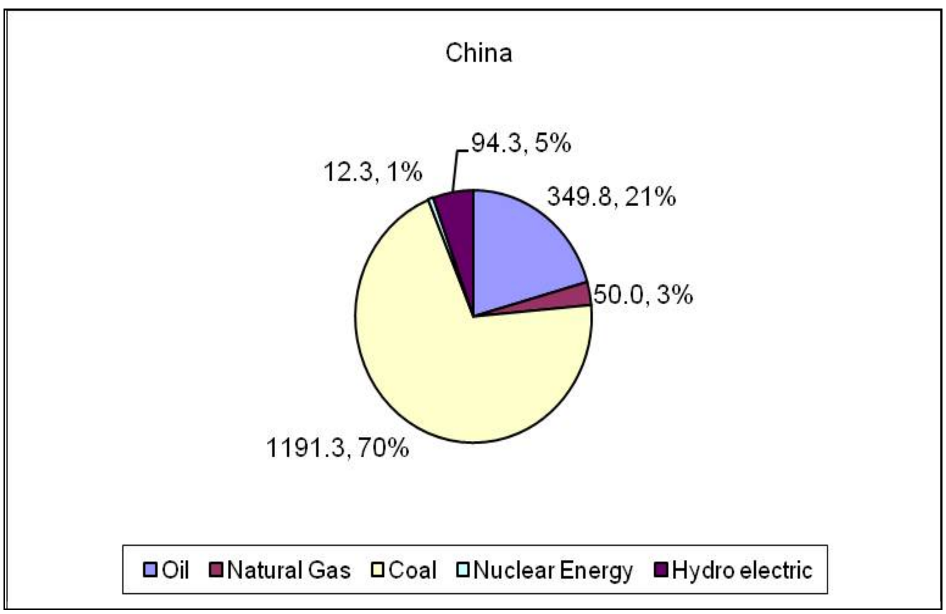

Exhibit:4.8 China- Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves and Production

Historically, natural gas has not been a major fuel in China, but its share in the country's energy mix is increasing. Oil & Gas Journal (OGJ) estimates that China's domestic proven reserves of natural gas stood at 53.3 trillion cubic feet (TCF) on January 2006. Other sources have put the reserves much higher.

Cedigaz estimates that China held 83 TCF of proved natural gas reserves as on January 2006. In 2004, natural gas accounted for only around 3 percent of total energy consumption in China, but this figure is expected to rise in the coming years. Until recently, natural gas was used primarily as feedstock in chemical fertilizer production and as energy source at oil and gas fields. As with oil, the natural gas sector is dominated by the three large state-owned oil and gas holding companies: CNPC, Sinopec, and CNOOC. CNPC operates primarily through its chief subsidiary PetroChina. All three companies operate numerous local subsidiaries. CNPC is the country's largest natural gas player in terms of production and reserves. CNPC data shows that the company produced 1.3 TCF of natural gas in 2005 which increased by 28 percent year by year. Sinopec reports that in 2005 the company produced a total 222 BCF of natural gas, which is a 7 percent increase from the previous year. The operating data of the third company CNOOC shows that it produced 142 BCF of natural gas in 2005, which is a 7 percent increase from 2004. One major hurdle for natural gas projects in China is the lack of a unified regulatory system. Currently, natural gas prices are governed by a patchwork of local regulations. The Chinese government is in the process of drafting a new legal framework for the natural gas sector. However, the process has been slow, and there are still considerable uncertainties regarding price regulation and taxation issues dealing with natural gas sales. The country's largest reserves of natural gas are located in western and north-central China. Several recent discoveries of natural gas, if successfully developed, promise to significantly increase China's natural gas production in the coming years. In July 2006, Sinopec officials revealed that the company had uncovered three new natural gas fields in northeast China holding an estimated 2.1 TCF of recoverable reserves. In April 2006, Sinopec confirmed a much larger discovery at the Puguang natural gas field in the southwestern province of Sichuan. The Puguang field holds proven recoverable reserves of 8.9 TCF, according to an official assessment by China's State Ministry of Land and Resources. In another significant move at the end of 2005, PetroChina announced that it had discovered an additional 3.5 TCF of recoverable natural gas reserves at the existing Daqing oil and gas field in northeast China's Heilongjiang province. The discovery of the Puguang natural gas field makes it one of the largest natural gas fields in China. The largest find till date is the Sulige field in the Ordos basin in the Inner Mongolia Autonomous Region. This has proven recoverable reserves of 18.9 TCF. In March 2006, PetroChina and PSC to jointly develop the South Sulige block. Another large natural gas field, the Kela-2 field in the Tarim basin, holds proven reserves of 8.9 TCF. PetroChina declared that it expects to produce 85 BCF from the Kela-2 field, eventually raising output to more than 700 BCF annually in 2010 to supply the company's West-East natural gas pipeline.

The key gas fields of China are shown in Table 4.7.

S.No.	Location	Name	Comments
1	Xinjiang province, far West china	Tarim Basin	226.4 BCM, 12 BCM/ yr
2	Southeast China	Sichuan Basin	Output around 8.26 BCM/yr
3	Far northwest China	Junggar Basin	1.23 TCM
4	Central China	Ordos basin includes Shaan Gas Ning, Changging & Changbei field	4.25 TCM
5	Northern coastal China	Bohai Bay	2.12 TCM
6	Central coastal China	East China Sea basin, includes Xihu Trough and Pinghu field	2.5 TCM
7	South China Sea	Qiongdongnam and Yinggehi Basins	1.63 TCM and 2.4 TCM reserves

Table:4.7 China- Key Gas Fields

Gas Surplus/ Deficit projection

The gas surplus/ deficit projection for China up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. The details calculated are shown in Table 4.8

China - (Reserve-371 MMSCMD)

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	168	219	305	423	588
Production	177	209	249	289	297
Export/Import	9	-10	-55	-134	-291
Surplus/deficit	203	152	67	-52	-217

(All Figs are in MMSCMD)

Table:4.8 China- Projection of Surplus/ Deficit of Gas

The status of actual production, consumption & export/ import from 1998 to 2004 is shown in Exhibit 4.9.

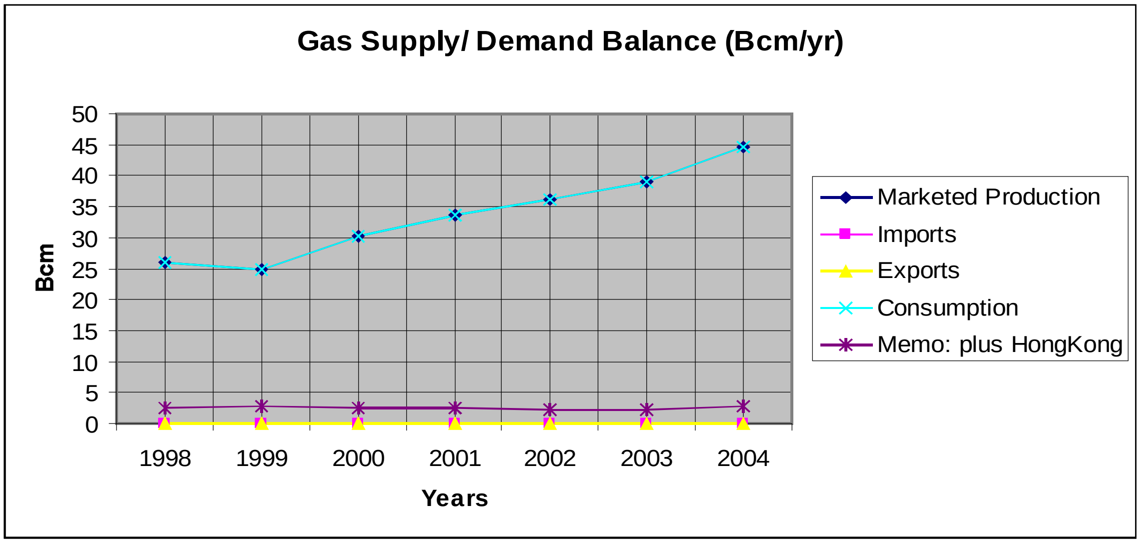

Exhibit:4.9 China- Gas Supply/ Demand 1998-2004

4.3.4 RUSSIA

Russia holds the world's largest natural gas reserves, the second largest coal reserves, and the eighth largest oil reserves. Russia is also the world's largest exporter of natural gas, the second largest oil exporter and the third largest energy consumer. In 2006, Russia's real gross domestic product (GDP) grew by approximately 6.7 percent, surpassing average growth rates in all other G8 countries. This marked the country's seventh consecutive year of economic expansion. Russia's economic growth over the past seven years has been driven primarily by energy exports, given the increase in Russian oil production and relatively high world oil prices during the period. Internally, Russia gets over half of its domestic energy needs from natural gas, up from around 49 percent in 1992. Since then, the share of energy use from coal and nuclear has stayed constant, while energy use from oil has decreased from 27 percent to around 19 percent.

Energy Policy

The Russian government has made it a priority to decouple economic growth from commodity exports. But, nationalizing parts of the energy sector has come at the expense of Russian oil and natural gas producers, who are seeking to grow in a more liberalized marketplace. Russia's external trading partners have also been pressurizing the country to synchronize its policies with those in Western Europe and North America. Key to these efforts will be breaking up of monopolies that control the natural gas and electricity industries. Policy makers continue to exhibit an inclination to advance the state's influence in the energy sector, not to reduce it. Taxes on oil exports have been raised significantly and private oil companies complain that higher export taxes are hindering efficient allocation of profits into exploration and development. State-owned export facilities have grown at breakneck pace, while private projects have either progressed slowly or met roadblocks set by state-owned companies Gazprom and Transneft.

In recent years there has been a noticeable increase in contacts between the oil and gas sectors of Russia and those countries in Central Asia which possess significant stocks of hydrocarbons and have the potential to export oil and gas, namely Kazakhstan, Turkmenistan and Uzbekistan.

In the history of cooperation between Russia and the Central Asian states on oil and gas matters, significant milestones were the creation in 2002 of a "gas alliance" between Russia, Kazakhstan, Turkmenistan and Uzbekistan, and the approval in 2003 by the international council of Eurasian Economic Community of the joint document "Principles of the Energy Policy of the member states of the Eurasian Economic Community". From the political point of view, these events, along with the arrival of Vladimir Putin to power in Russia, and the entrance of Uzbekistan into the Eurasian Economic Community in 2006, were key factors leading to a breakthrough in cooperation in the oil and gas sectors.

In general the structural interdependence of Russia and the countries of Central Asia in the energy sector are much reduced now as compared with Soviet times. The reduced volume of trading in oil and gas between these countries is a reflection of this, and the previous well-developed cooperation plan between republics has been wholly or partly destroyed.

Primary Energy Mix & Sectoral Analysis

Table 4.9 shows the distribution of growth in total primary energy demand in various sectors like Power, Industry, Transport and other sectors.

[Source: World Energy Outlook]

RUSSIA								
	Energy Demand(MTOE)			Share (%)			Growth (% p.a)	
	2005	2015	2030	2005	2015	2030	2005-215	2005-2030
Total primary energy demand	645	766	871	100	100	100	1.7	1.2
Coal	103	125	131	16	16	15	1.9	1
Oil	133	152	166	21	20	19	1.3	0.9
Gas	348	416	473	54	54	54	1.8	1.2

Nuclear	39	46	68	6	6	8	1.6	2.3
Hydro	15	16	17	2	2	2	0.8	0.6
Biomass & waste	7	7	6	1	1	1	-0.4	-0.3
Other renewables	0	4	8	0	0	1	26.3	13.5
Power generation	354	403	450	100	100	100	1.3	1
Coal	77	93	97	22	23	22	2	0.9
Oil	16	15	12	5	4	3	-0.7	-1.3
Gas	202	226	245	57	56	54	1.1	0.8
Nuclear	39	46	68	11	11	15	1.6	2.3
Hydro	15	16	17	4	4	4	0.8	0.6
Biomass & waste	4	3	3	1	1	1	-1.5	-1.6
Other renewable	0	4	8	0	1	2	26.1	13.5
Other energy sector	93	109	122	100	100	100	1.6	1
Electricity generation (TWH)	946	1126	1352	100	100	100	1.8	1.4
Coal	166	226	293	18	20	22	3.2	2.3
Oil	20	18	13	2	2	1	-0.9	-1.7
Gas	435	508	550	46	45	41	1.6	0.9
Nuclear	149	176	261	16	16	19	1.6	2.3
Hydro	173	188	200	18	17	15	0.8	0.6
Biomass & waste	3	2	13	0	0	1	-3.7	6.6
Other renewables	0	8	22	0	0	2	140.4	57.1

Table:4.9 Russia- Sectoral Energy Analysis

54.8 percent of the total energy demand is in the power sector. Gas is an important fuel in the power sector. It fulfils 202 MTOE of energy demand out of a total 354 MTOE. Gas usage is increasing at a growth rate of 1.1 percent, which is rather good.

Gas plays an important role in electricity generation. It generates more than 45 percent of the total electricity generated in the country, and is increasing at a growth rate of 1.6 percent. After gas, hydro power is used to generate electricity. It generates 18.2 percent of total electricity needed and is increasing at a growth rate of 8 percent.

Russia's primary energy demand mix for 2006 is shown in Exhibit 4.10.

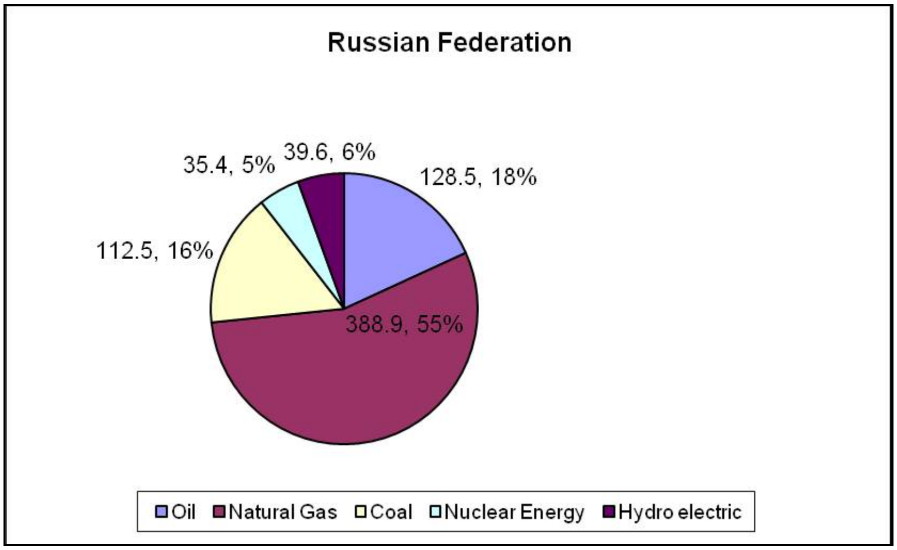

Exhibit: 4.10 Russia- Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves & Production

Russia holds the world's largest natural gas reserves, with 1,680 trillion cubic feet (TCF). This is twice the reserves in the next largest country, Iran. Accordingly, in 2004 Russia was the world's largest natural gas producer (22.4 TCF), as well as the world's largest exporter (7.1 TCF). Production during 2005 was about the same. However, Russia's natural gas industry has not been as successful as its oil industry, with both natural gas production and consumption remaining relatively flat since independence. Further, Gazprom's natural gas production forecast calls for only modest growth (about 1.3%) by 2008. Russia's natural gas sector has been stunted primarily due to aging fields, state regulation, Gazprom's monopolistic control over the industry, and insufficient export pipelines. Three major fields (called the 'Big Three') in Western Siberia — Urengoy, Yamburg, and Medvezh'ye — comprise more than 70 percent of Gazprom's total natural gas production. These fields are, however, now in decline. Although the company projects increases in its natural gas output between 2008 and 2030, most of Russia's natural gas production growth will come from independent gas companies such as Novatek, Itera, and Northgaz.

The key gas fields of Russia are shown in Table 4.10.

[Source: World Gas Handbook 2005-06]

Key Gas Fields			
S.No	**Location**	**Name**	**Comments**
1	Yamal-Nenets, northwestern Siberia	Urengoiskoye	Reserves 5.37 TCM
2	Yamal-Nenets, northwestern Siberia	Yamburgskoye	Reserves 4.13 TCM
3	Volga-Urals	Orenburg	Reserves 805.7 BCM
4	Yamal-Nenets, northwestern Siberia	Zapolarnoye	Reserves 3.42 BCM
5	Yamal-Nenets, northwestern Siberia	Bovanenkovskoye	Reserves 4.37 TCM
6	Astrakhan Region	Astrakhanskoye	Reserves 2.5 TCM
7	Irktusk, eastern Siberia	Kovykta	Reserves 2 TCM
8	Barents Sea, 500 km north of Murmansk	Shtokmanovskoye	Reserves 3.2 TCM

Table: 4.10 Russia- Key Gas Fields

Import and Export Markets

Russia exports significant amounts of natural gas to customers in the Commonwealth of Independent States (CIS). In addition, Gazprom (through its subsidiary Gazexport) has shifted much of its natural gas exports to serve the rising demand in countries of the EU, as well as Turkey, Japan, and other Asian countries. Raising domestic demand in 2006, Gazprom, which has a monopoly on Russian gas exports, transported 5.3 TCF (roughly 60 percent) to destinations outside the CIS and the Baltic states. This was with an increase of 3 percent from 2005. Exports of Russian gas to neighboring Baltic and CIS countries totaled 1.3 BCF in 2006 (not including re-exports of Central Asian gas).

Gas Surplus/ Deficit Projection

Calculation of gas surplus/ deficit projection for Russia up to 2025 is based on the actual status of 2006 on demand/ production and the estimated reserve.

The calculated details are shown in Table 4.11.

Russia (Reserve 7220 MMSCMD)

Year	2006	2010	2015	2020	2025
Demand	1309	1474	1708	1981	2296
Production	1855	2048	2289	2530	2771
Export/Import	546	574	581	550	475
Surplus/deficit	5910	5746	5511	5239	4924

(All Figs are in MMSCMD)

Table: 4.11 Russia- Projection of Surplus/ Deficit of Gas

The status of actual production, consumption & export/ import for the year 1998 to 2004 is shown in Exhibit 4.11.

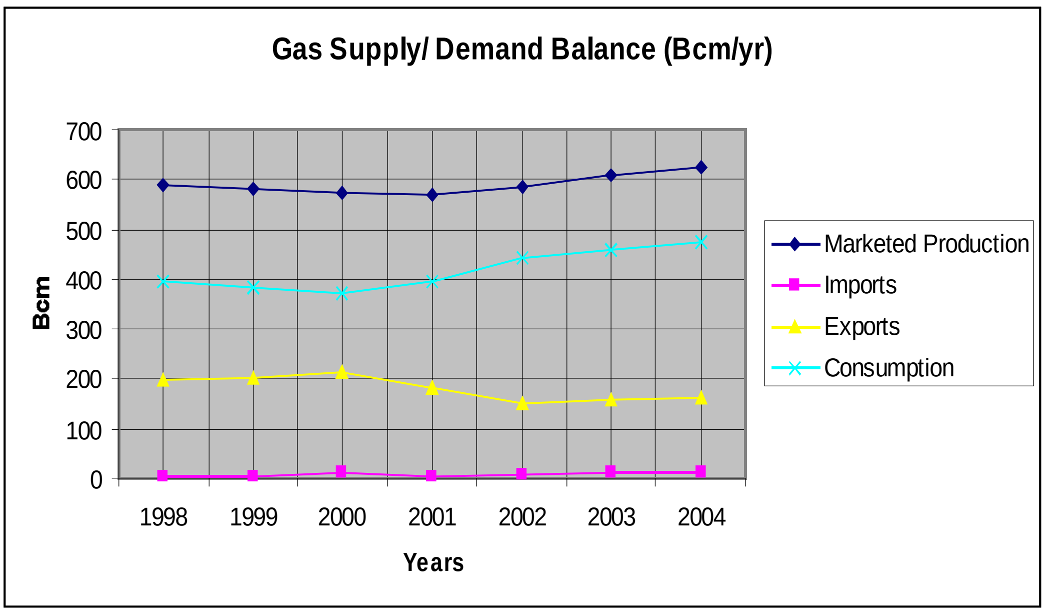

Exhibit: 4.11 Russia- Gas Supply/ Demand 1998-2004

4.3.5 KAZAKHSTAN

Kazakhstan is important to world energy markets because it has significant oil and natural gas reserves. After years of foreign investment into the country's oil and natural gas sectors, the landlocked Central Asian state has recently begun to realize its enormous production potential. With sufficient export options, Kazakhstan could become a major world energy producer and exporter over the next decade. Kazakhstan has the Caspian Sea region's largest recoverable crude oil reserves, and its production accounts for over half of the roughly 2.8 million barrels per day (bbl/d) currently being produced in the region (including regional oil producers Azerbaijan, Uzbekistan, and Turkmenistan). Oil exports are the foundation of Kazakhstan's economy and have ensured that average real GDP growth has stayed above 9 percent for the last 6 years. Real GDP growth during 2007 averaged 9.5 percent. Kazakhstan's growing petroleum industry accounts for roughly 30 percent of the country's GDP, and over half of its export revenues. In an effort to reduce Kazakhstan's exposure to price fluctuations for energy and commodities exports, the government created the National Oil Fund of Kazakhstan. Due to high oil prices the international reserves and assets in the oil fund have doubled in the last year to $20 billion in October 2007. Kazakhstan is gradually becoming one of the pillars of energy security in Asia and Europe, as it plans to produce 3.5 million barrels of oil a day (MBD) and 60-80 billion cubic meters (BCM) of associated gas by 2015.

Over the past decade, the development of new oil and gas fields in Kazakhstan has generated an increasing interest in new export routes to Europe and more recently to China. This is in addition to its historic dependence on Russian pipelines. Kazakhstan views multiple pipelines as the key to its efforts to ensure that no regional power can exercise strategic control over its energy routes and its broader economic and political ties to western, Mediterranean, and Asian partners. US, European and Asian energy companies too favour multiple pipelines to ensure reliable market access and predictable commercial regime so as to avoid excessive transit fees set by any one pipeline operator and mitigate geopolitical risks. Furthermore, since gaining its independence fifteen years ago, Kazakhstan's importance has considerably increased as a geopolitical power on the former Soviet geography, sandwiched between China and Russia, due to its "multi-vectoral" relations with powerful neighbours, the US, the EU and Japan. It is now recognised as a key power to reckon with in Eurasia. Kazakhstan's expanding cross-border energy links with Russia, China, other Central Asian countries, and possibly Europe via Turkey, will likely enhance its independence, economic development/diversification and geopolitical standing.

Energy Policy

Despite Kazakhstan's sizeable proven natural gas reserves, the country spent most of its time after independence as a net natural gas importer. Natural gas production has increased significantly since 1999, when the Kazakh government passed a law requiring subsoil users (such as oil companies) to include natural gas utilization projects in their development plans. As a result, natural gas production has been on a steady increase since 1999, and by 2000 it eclipsed its pre-independence production levels. By 2003, however, Kazakhstan's production had reached parity with its consumption level (approximately 550 BCF), and the country had 40 TCF in net exports of natural gas during the first half of 2005.

In 2005, natural gas production in Kazakhstan reached 26.2 BCM. According to the 15-year strategy of the Kazakh Ministry for Energy and Mineral Resources, the country plans to boost gas output by more than 40 BCM (with exports up to 15 BCM) by 2010-2012. Kazakh energy officials estimate that internal consumption of around 900 BCF in 2010 will leave 700 BCF for export (*USEIA, 2006*). The remaining volume will be re-injected and used for domestic consumption, including power generation needs.

Lack of available gas export infrastructure is the primary inhibitor to larger scale exports from Kazakhstan. The country became a net natural gas exporter in 2004. Development of internal gas distribution lines connecting the northern and southern areas of the country is expected to help expand natural gas development. Kazakhstan has two separate domestic natural gas distribution networks, operated by Kazmunaigas subsidiaries. One in the west services the country's producing natural gas fields, and the other in the south mainly delivers imported natural gas to the southern consuming regions. The lack of internal pipelines connecting these gas producing areas to the country's industrial belt (between Almaty and Shymkent) has hampered the development of natural gas resources. However, the development of the Amangeldy gas field will help Kazakhstan's southern region cease importing Uzbek gas. Natural gas development in Kazakhstan requires long-distance transit. Access to markets - not only in Russia and other Central Asian countries, but also in Central and Western Europe, Turkey, and China - is the key to further development.

Kazakhstan’s primary energy demand mix for 2006 is shown in Exhibit 4.12.

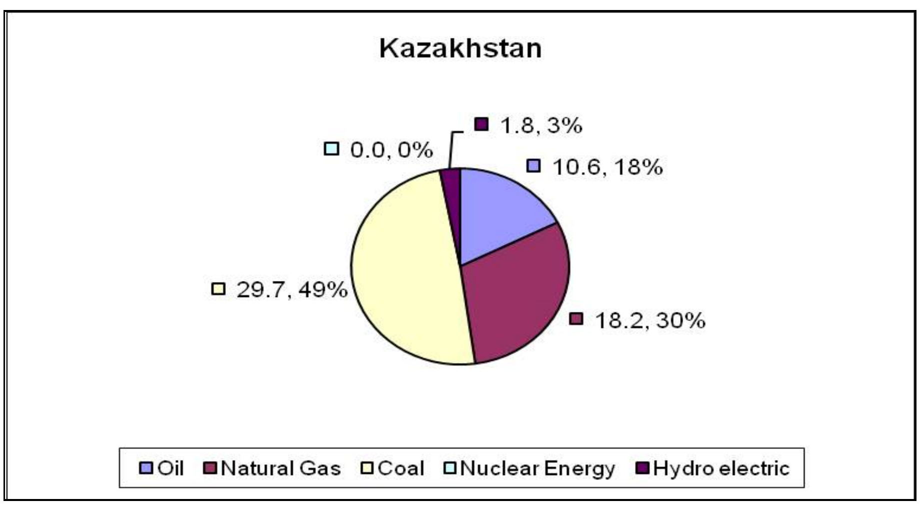

Exhibit 4.12 Kazakhstan - Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves and Production

Kazakhstan’s proven gas reserves are 3 TCM and projected gas reserves are 5 TCM. The country also has significant amounts of oil and associated gas. Every new tonne of oil is expected to bring 1000 cubic meters of gas (with 100 million tons of new oil it is about 100 BCM of gas). This shows the importance of rational utilisation of gas not only by its re-injection, but also through exports and internal use (liquefaction, development of internal gas pipeline infrastructure). With large amounts of associated natural gas at its oil fields, Kazakhstan has the potential to become a net exporter in upcoming years. However, the lack of available gas export infrastructure will limit export growth.

Kazakhstan produces about as much natural gas as it consumes. Following maintenance at Tengiz and Karachaganak in the last couple of years, the country is poised to become a net exporter soon. The Kazakhstan Energy Ministry estimated that production during 2007 totalled 1,037 billion cubic feet (BCF). Over 70 percent of this oil was produced by international consortia at the Tengiz and Karachaganak fields. Gas production has increased by over 8 percent from the previous year.

In 2007, the Oil and Gas Journal upwardly revised its estimate of proved natural gas reserves in Kazakhstan to 100 trillion cubic feet (TCF). This put the country at par with Turkmenistan. Most of Kazakhstan's natural gas reserves are located in the west of the country, with roughly 25 percent of proven reserves situated in the Karachaganak field. This oil and gas condensate field has reportedly proven natural gas reserves of 48 TCF. The consortium developing Karachaganak expects to produce 900 BCF by 2012.

Natural gas in Kazakhstan is almost entirely "associated" gas. Several fields including Karachaganak re-inject significant quantities of gas into the ground to maintain crude wellhead pressure for extracting liquids. In the long term, even when the liquids are exhausted, this gas can be recovered. The largest source of natural gas in the country is the Karachaganak natural gas and condensate field which produced 503 BCF in 2007, up by more than 18 percent from the previous year. The consortium estimates that the field contains over 47 TCF (1.35 TCM) of natural gas reserves.

The key gas fields of Kazakhstan are shown in Table 4.12.

[Source: World Gas Handbook 2005-06]

Key Gas Fields			
S.No.	**Location**	**Name**	**Comments**
1	Northwestern Kazakhstan	Karachaganak	450 BCM
2	Eastern share of Caspian Sea	Tangiz/ Kereley	500 BCM
3	Offshore, northeast Caspian Sea	Kashagan	Operated by Eni. Production slated to begin 2005
4	Zhambyl region, southern Kazakhstan	Amangeldy and Ayrykty	Combined reserves of 22.6 BCM

Table:4.12 Kazakhstan-Key Gas Fields

Gas Surplus/ Deficit Projection

The gas surplus/ deficit projection for Kazakhstan up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve.

The details calculated are shown in Table 4.13.

Kazakhstan (Reserves-455 MMSCMD)

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	61	69	80	93	108
Production	73	87	105	123	141
Export/Import	11	18	25	30	34
Surplus/deficit	393	386	375	362	347

(All Figs are in MMSCMD)

Table:4.13 Kazakhstan - Projection of Surplus/ Deficit of Gas

The status of actual production, consumption & export/ import for the year 1998 to 2004 is shown in Exhibit 4.13.

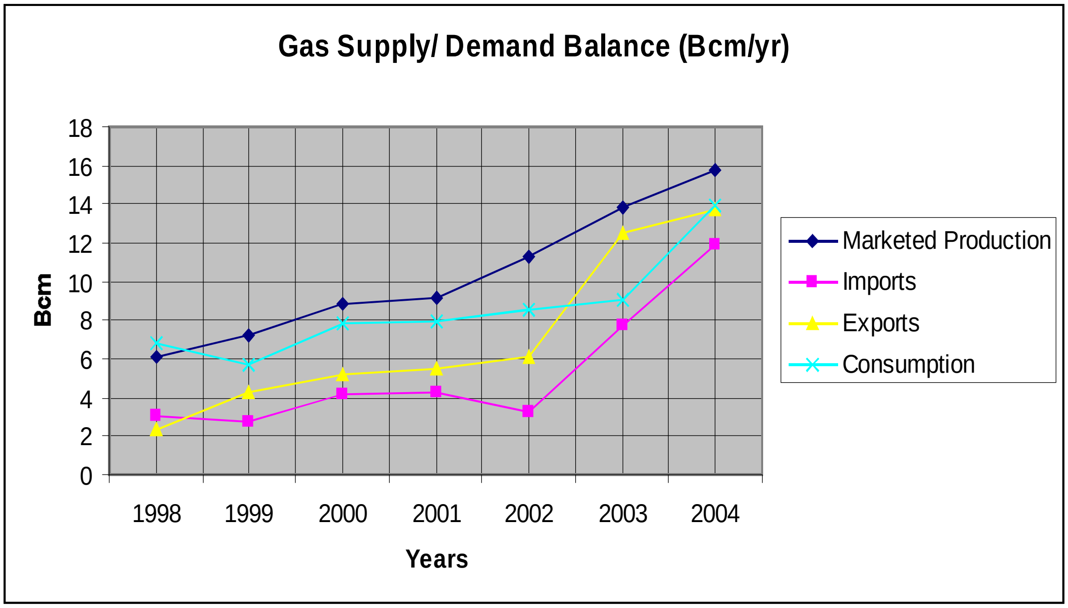

Exhibit:4.13 Kazakhstan - Gas Supply/ Demand 1998-2004

4.3.6 AFGHANISTAN

Afghanistan has a democratically elected government. After winning an election, President Hamid Karzai was officially inaugurated on October 9, 2004. The members of the National Assembly were elected in September 2005 and took office in December 2005. In 2001, a U.S.-led coalition had defeated the previous Taliban government which had provided sanctuary in the country, for the terrorist group al-Qaeda. After more than two decades of war and chaos, and three years of drought in the late 1990s, Afghanistan's primarily agricultural economy was in poor condition at the end of 2001 when the Taliban was removed from power. Since then, there has been marked improvement. During the Afghan fiscal year from March 21, 2004 to March 20, 2005, the GDP growth was 8 percent. Foreign aid has been helpful to Afghanistan, and pledges of assistance now total almost $15 billion. In March 2004, President Karzai presented at a conference in Berlin, a $28 billion, 7-year economic development program. He urged the foreign donors at the conference to renew their commitments to Afghanistan. It is estimated that Afghans living outside the country had invested $3 billion in Afghanistan (out of an economy with GDP of around $6 to $7 billion). The government has been pushing the financial sector and customs reforms, along with a plan to promote private investment in the energy sector.

Energy Policy

Afghanistan has long been considered a potential pipeline route due to its location between the oil and natural gas reserves of the Caspian Basin and the Indian Ocean. There have, however, been several obstacles to building a pipeline across the country. During the mid-1990s, Unocal had pursued a possible natural gas pipeline from Turkmenistan's Dauletabad-Donmez gas basin via Afghanistan to Pakistan. They pulled out after the U.S. missile strikes against Afghanistan in August 1998. The Afghan government under President Karzai has tried to revive the Trans-Afghan Pipeline (TAP) plan, with periodic talks between the governments of Afghanistan, Pakistan, and Turkmenistan. On December 9, 2003 a protocol on the pipeline was signed by the governments of Afghanistan, Pakistan and Turkmenistan. President Karzai has stated his belief that the project could generate $100-$300 million per year in transit fees for Afghanistan, while creating thousands of jobs in the country. Financial problems in the utility sector in India, which would be the major consumer of natural gas, also could pose a problem for construction of the TAP line. The pipeline's estimated cost of $2.5 - $3.5 billion, could be an obstacle to its construction. The Asian Development Bank had sponsored a feasibility study of the project by the British firm Penspen. This was completed in January 2005. The study indicates that the TAP is promising. It envisions a 56-inch diameter pipeline, with a design capacity of 1.16 TCF per year. The pipeline would start in Turkmenistan and run 1,043 miles through Afghanistan and Pakistan, terminating at Fazilka, a frontier station on the Indian border. The feasibility study estimated a cost of $3.3 billion. Now the Indian government is also willing to take part in this project.

Natural Gas Reserves and Production

Between the 1960s and mid-1980s, the Soviets had identified more than 15 oil and gas fields in northern Afghanistan. Only three gas fields -- Khwaja Gogerdak, Djarquduk, and Yatimtaq – were developed in the area surrounding Sheberghan. These are located about 120 kilometres west of Mazar-i-Sharif.

Afghan natural gas production reached 275 million cubic feet per day (MMCF/d) in the mid-1970s. The Djarquduk field was brought online during that period and boosted Afghan natural gas output to a peak of 385 MMCF/d by 1978. About 100 MMCF/d of this amount was used locally in gas distribution systems in Sheberghan and Mazar-i-Sharif as well as at a 100,000 mt/y urea plant located near Mazar-i-Sharif. Northern Afghanistan has proved, probable and possible natural gas reserves of about 5 TCF. This area, which is a southward extension of the highly prolific, natural gas-prone Amu Darya Basin, has the potential to hold a sizable undiscovered gas resource base, especially in sedimentary layers deeper than what were developed during the Soviet era. Outside the North Afghan Platform, very limited oil and gas exploration has occurred. Geological, aeromagnetic, and gravimetric studies were conducted in the 1970s over parts of the Katawaz Fault Block (eastern Afghanistan – along the Pak border) and in the Helmand and Farah provinces. The hydrocarbon potential in these areas is thought to be very limited as compared to that in the north. Limited oil and natural gas exploration has occurred in Afghanistan.

Gas Surplus/ Deficit projection

The gas surplus/ deficit projection for Afghanistan up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. The details calculated are shown in Table 4.14.

Source: www.index mundi

Afghanistan (Reserves-7.20 MMSCMD)

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	0.058	0.065	0.076	0.088	0.102
Production	0.058	0.058	0.058	0.058	0.058
Export/Import	0	-0.007	-0.018	-0.03	-0.044
Surplus/deficit	7.143	7.136	7.126	7.114	7.1

(All Figs are in MMSCMD)

Table:4.14 Afghanistan - Projection of Surplus/ Deficit of Gas

4.3.7 TURKMENISTAN

Turkmenistan became an independent country on December 25, 1991, following the dissolution of the Soviet Union. It is governed by a constitution that was adopted in May 1992 which effectively concentrates all political power in the office of the president. There is no provision for a vice president or a prime minister and in the event of the death of the president, power is handed over to the chairman of the legislature. The president nominates all the candidates for the People's Council (Halk Maslakhaty), chooses the members of the Cabinet of Ministers, the country's leading judges, and the heads of the provincial, municipal, and local administrations.

Turkmenistan is geographically far from the end-use markets they serve and lack sufficient pipeline infrastructure to export more hydrocarbons. Further, other hydrocarbon-rich Central Asian and Caspian states with more favorable investment climates and greater access to markets, pose competition for Turkmenistan. The country is eager to diversify export routes for their resources outside of the Russian-controlled pipelines, but it must seek to obtain capital, technical assistance, and political support for alternative pipelines.

Turkmenistan was still eager to attract foreign investment in its oil and gas sectors. In the early years, numerous representatives of Western firms came to Turkmenistan to assess what was on offer and judged that the country's gas was an attractive prize if new transport routes could be found for it.

Two new routes offered the potential for good return on capital invested, with little need for technological innovation. The first would take Turkmen gas across Iran and then on through Turkey to markets in Europe. The second would send Turkmen gas through Afghanistan to markets in Pakistan and India. A third possibility, which offered long-term potential as new technology came on line, was to send Turkmen gas across Central Asia to the ports of eastern China and then possibly on to Japan. There was also strong U.S. government support for Turkmen gas to be shipped via a Baku-Tbilisi-Erzurum pipeline across the Caspian Sea, parallel to the Baku-Tbilisi-Ceyhan oil pipeline. As of now, only a single pipeline has been built, which moves Turkmen gas from Korpedzhe to Kurt-Kui (in Iran). The larger Turkmen-Iranian pipeline and trans-Afghan pipeline projects were put on hold. Turkmenistan received little new capacity from the Korpedzhe to Kurt-Kui line (only 4.5 BCM per year) although the pipeline can handle 10 BCM per year with additional compression. Hence, at least for now, Turkmenistan is forced to market the bulk of its production through Russia, under terms that favor Russian interests over Turkmen ones.

The country's gross domestic product (GDP) is export driven, with the principal commodities (gas, oil, and cotton) all largely under state control. After several years of declining GDP, Turkmenistan has begun to report high rates of economic growth due to increased gas exports through Russia.

The average per capita income in Turkmenistan is $950 USD, and this includes the market value of a host of state subsidies on communal services and foodstuffs. These generous subsidies, combined with the dilapidated state of infrastructure in the gas and power supply system, have created unsustainable increases in domestic gas consumption. According to the IEA, 80 percent of primary energy supplies in Turkmenistan are dependent upon natural gas, and only 55 percent of the power generated in the country goes to various industrial usages. Current domestic gas consumption is about 10 billion cubic meters (BCM) per annum. The World Bank estimates that the Turkmen government spent $600 million USD on subsidies to the energy sector in 2000. The Bank feels this money could have been better spent addressing the country's deteriorating energy infrastructure.

Energy Policy

Turkmenistan has proven gas reserves of approximately 2.86 TCM in assets spread across some 150 separate oil and gas deposits. The exploitation of Turkmenistan's gas fields began in earnest in 1950s, well after the gas industry was established in the Russian Volga region. New fields continue to be discovered, and during the last ten years the Turkmen government has identified new natural gas deposits in the Lebansky Marynsky, and Deashoguzsky regions of the country, some of which have begun to be developed. In addition, the president's economic program also calls for Turkmengaz, the state-run company, to step up exploratory work in the Karakum and Kyzylkum deserts. The Turkmen government sought to provide a legal regime that would attract foreign investment in its oil and gas sector, in both development and expanded exploitation of fields, including the transport sector. Though the government promulgated many laws, it provided no real protection for investments. The existing legislation includes a Law on Foreign Investment enacted in May 1992 and amended in April 1993.This law guarantees that foreign investments are not subject to nationalization or requisition. Foreign firms are granted concessions between 5 and 40 years for onshore and offshore areas containing natural resources, as well as for investment in enterprises that explore, develop, extract, and use natural resources.

Turkmenistan’s primary energy demand mix for 2006 is shown in Exhibit 4.14.

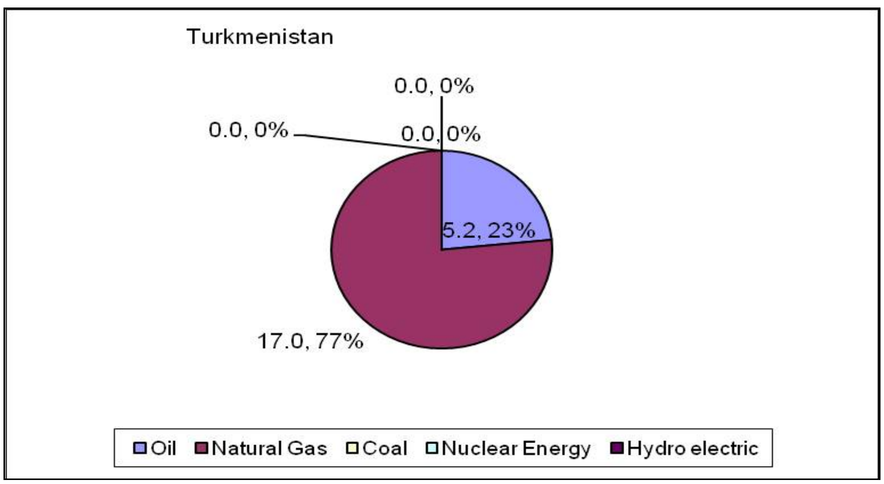

Exhibit:4.14 Turkmenistan - Primary Energy Demand for 2006 (MTOE)

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Natural Gas Reserves and Production

Since the Soviet Union’s collapse in 1991, Central Asian regional natural gas production has been characterized by modest annual increases from Uzbekistan, and by a collapse (then partial recovery) from Turkmenistan. After 1991, these fluctuations occurred because Turkmenistan was locked in pricing disputes with Russia and other countries until 1998. This resulted in Russia cutting access to its pipelines. Since all pipelines connecting the region to world markets were owned by Russia’s state owned gas company Gazprom, and routed through Russia, Turkmen natural gas was squeezed out of the market. As a result, Turkmenistan's ability to attract investment for existing field development disappeared. The country's output dropped throughout the 1990s, from 2 trillion cubic feet (TCF) per year (57 BCMm/y) in 1992 to 466 billion cubic feet (BCF) per year (13 BCM/y) in 1998. In 1999, a Turkmen-Russian agreement came into effect, and the next year, production skyrocketed to 1.6 TCF/y (47 BCM/y) before reaching an estimated 2.2 TCF/y (63 BCM/y) in 2006. This placed the country as the second largest gas producer after Russia in the former Soviet bloc. In May 2007, chairman of Turkmengaz, Yashygeldy Kakayev, said the country's energy strategy is to double gas production to 4.2 TCF/y (120 BCM/y) in 2010 and more than triple production to 8.48 TCF/y (240 BCMy) by 2030. In early 2008, the Turkmen government announced that it plans to produce 2.6 TCF/y (73 BCM of gas in 2008.

Turkmenistan had proven natural gas reserves of approximately 100 TCF (2.83 TCM) at the end of 2007, up from 71 TCF (2 TCM) the previous year, according to the Oil and Gas Journal. This reserve level ranks Turkmenistan among the top 12 countries in terms of natural gas reserves.

Turkmenistan contains several of the world's largest gas fields, including 10 with over 3.5 TCF of reserves located primarily in the Amu'Darya basin in the east, the Murgab Basin, and the South Caspian basin in the west. All major gas fields in Turkmenistan have been producing for more than a quarter century and are exhibiting signs of natural depletion. Of the gas available for future exploration and development, the Turkmen government wants to produce offshore associated gas reserves from its section of the Caspian Sea. Some sources such as Heren Energy and Western Geophysical (US) estimate recoverable offshore reserves over 210 TCF (6 TCM). Berdymukhammedov is in discussion with major companies such as Chevron, Total, Shell, Lukoil, Gazprom, Itera, and BP to explore and develop Turkmenistan's part of the Caspian shelf. According to RPI Research, Petronas which has an oil and gas PSA with Turkmenistan for the Diyarbekir field (Block 1), estimates that the field has 5.3 TCF (150 BCM) of reserves with production levels of up to 353 BCF/y (10 BCM/y) for 20 years. Also, Dragon Oil has 3.5 TCF (100 BCM) of gas reserves in the Cheleken field. A Russian consortium (Rosneft, Itera, Zarubezhneft) anticipates signing a PSA with Turkmenistan to develop several Caspian blocks.

The Dauletabad field, located in the Amu'Darya basin and had about 60 TCF (1.7 TCM) of gas before being brought into production in 1982. It was deemed as one of Turkmenistan's largest fields. In 1997, reserves at the field were independently certified at an estimated 25 TCF (0.7 TCM) by the U.S.-based consultancy, DeGolyer and McNaughton. In 2005, the firm was hired by the Asian Development Bank (ADB) to re-assess the field's reserves and its ability to support a Trans-Afghan pipeline project. The results have never been released publicly, causing uncertainty for potential foreign investors. In November 2006 and March 2007, Turkmenistan announced the discovery of the South Yolotan and the Osman fields, respectively. These fields are possibly a single geological field and located in the southeastern Murgab Basin, north of the Dauletabad field. Former President Niyazov asserted that South Yolotan was the largest field in the world with reserves of 240 TCF (6.8 TCM); however, most analysts believe this number is significantly exaggerated. The reserve levels for both fields are extremely speculative. As reported in January 2008, Turkmenistan's state energy company was in discussion with an international company to perform audits of the Yolotan and Osman energy deposits. An affiliate of CNPC was awarded a $151 million 3-year drilling contract for 12 wells in South Yolotan in late 2006. Also, CNPC signed a PSA with Turkmenistan in July 2007 to develop the Turkmen sector of the Amu'Darya Basin including the Bagtiyarlyk field. From 2009, CNPC anticipates transporting up to 1.1 TCF/y (30 BCM/y) of gas from these fields to a proposed pipeline traversing Central Asia to China.

Gas Surplus/ Deficit Projection

The gas surplus/ deficit projection for Turkmenistan up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. Details of calculations are shown in Table 4.15.

TURKMENISTAN (Reserve-433 MMSCMD)

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	57	65	75	87	101
Production	189	222	265	307	347
Export/Import	131	158	190	221	246
Surplus/deficit	376	369	358	347	333

(All Figs are in MMSCMD)

Table: 4.15 Turkmenistan - Projection of Surplus/ Deficit of Gas

The status of actual production, consumption & export/ import for the year 1998 to 2004 is shown in Exhibit 4.15.

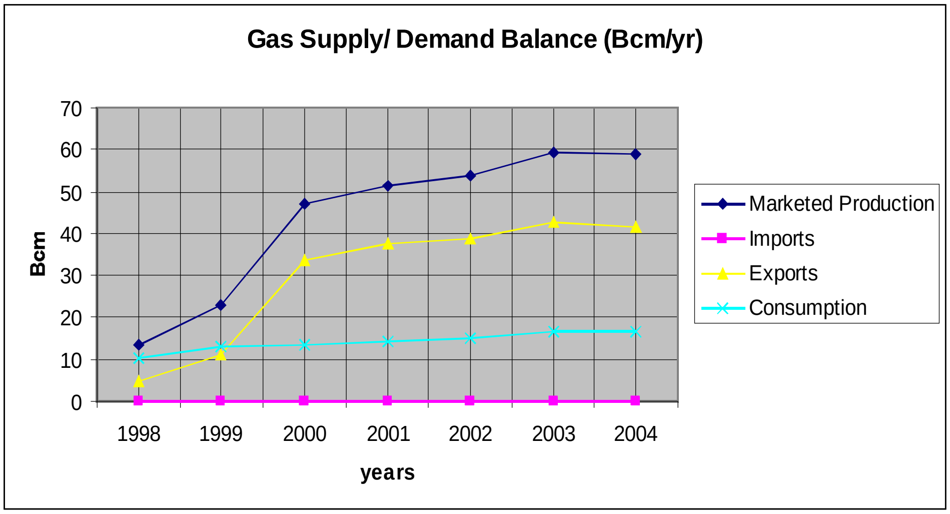

Exhibit: 4.15 Turkmenistan - Gas Supply/ Demand 1998-2004

4.3.8 UZBEKISTAN

Uzbekistan and Turkmenistan sit on large reserves of oil and natural gas, yet both countries face a myriad of challenges in bringing those reserves to world markets. Both countries are geographically far from the end-use markets they serve and lack sufficient pipeline infrastructure to export more hydrocarbons. Further, other hydrocarbon-rich Central Asian and Caspian states with more favorable investment climates and greater access to markets, pose competition for Turkmenistan and Uzbekistan. Both countries are eager to diversify export routes for their resources outside the Russian-controlled pipelines, but each must seek capital, technical assistance, and political support for such alternative pipelines.

Energy Policy

Uzbekistan has one of the lowest FDI levels in the former Soviet Union, and investment for the hydrocarbon industry is currently insufficient to raise oil production. According to the EBRD, total FDI for 2007 is estimated at $260 million; although the Uzbek government reports a higher FDI of $693 million. The discrepancy could be due to a difference in the types of investments included. Also, in 2005 only $114 million was slated for investment for oil and gas exploration, according to an International Crisis Group report. The Uzbek government has invested about $2 billion of mostly commercial and export credit loans in the hydrocarbon sector since 1991. In order to boost foreign investment, Uzbekistan recently took various steps such as reversing its previous tax level increases on subsoil hydrocarbon production which had been introduced in 2007 (now 20 percent and 30 percent tax for crude and gas production, respectively); and modifying its regulations for PSA (Production

Supply Agreement) developments. In addition, Uzbekistan has attempted to privatize Uzbekneftegaz several times since 2003, but its desire to maintain majority control over the company is thwarting its plans to attract foreign investors.

Uzbekistan’s primary energy demand mix for 2006 is shown in Exhibit 4.16.

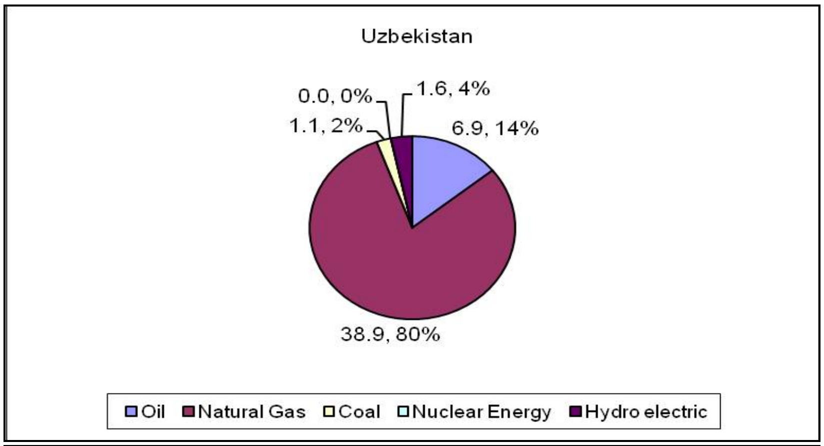

Exhibit: 4.16 Uzbekistan - Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves and Production

Uzbekistan has maintained growth in natural gas production by avoiding Russia’s pipeline system and by concentrating on the domestic market and exports to immediate neighbors. Holding estimated natural gas reserves of 65 TCF (1.8 TCM) according to Oil and Gas Journal, Uzbekistan is the third largest natural gas producer in the FSU (after Russia and Turkmenistan) and one of the top fifteen natural gas-producing countries in the world. Uzbekistan produces natural gas from 52 fields with 12 major deposits, including Shurtan, Kokdumalak, Gazli, Pamuk, and Khauzak. This accounts for over 95 percent of Uzbekistan's natural gas production. These deposits are concentrated in the Uzbek side of the Amu Dar'ya Basin in the southeast and in the Ustyurt plateau in the western part of the country. Since becoming independent, Uzbekistan has increased its natural gas production by nearly 40 percent, from 1.5 TCF/y (42 BCM/y) in 1992 to 2.1 TCF/y (60 BCM/y) in 2005. In 2006, Uzbek natural gas production increased to nearly 2.2 TCF/y (63 BCM/y). Uzbekistan's natural gas fields were heavily exploited in the 1960's and 1970's by the Soviet Union, and as a result several older fields, such as Uchkyr and Yangikazgan, are beginning to decline in production. In order to offset those declines, Uzbekistan is speeding up development at other fields, such as Garbi and Shurtan, as well as developing new fields and exploring for new reserves. Similar to Turkmenistan, Uzbekistan’s gas sector suffers from deficiencies of pipeline infrastructure in the region. Uzbekistan consumes a majority of its gas, and there are losses in the system due to pressure declines since the 1990s.

Further, according to estimates from a World Bank commissioned study conducted by the National Oceanic and Atmospheric Administration (NOAA), Uzbekistan currently flares nearly 105 BCF/y (3 BCM/y), which is 5 percent of the reported production levels. Although Kazakhstan now flares three times the amount of gas as its Central Asian neighbor, Uzbekistan ranks as one of the top 20 gas flaring countries.

Uzbekistan exported approximately 450 BCF/y (12.7 BCM/y) in 2006, up nearly 10 percent from 2005. It sends over half of its natural gas exports to Russia and the remainder to neighboring Central Asian states. Uzbekistan serves as a transit point for Turkmenistan's gas exports to Russia, which is pumped through Kazakhstan. The gas enters Russian territory at the Alexandrov Gay point, which is the entrance to the Central Asia-Central Russia line. According to Uzbekneftegaz, the country planned to boost gas exports in 2007 to 512 BCF/y (14.5 BCM/y), up 14 percent from 2006 levels. It hopes to export gas to China after the Turkmenistan to China pipeline is constructed. Uzbekistan plans to upgrade its gas infrastructure and export 565 BCF/y (16 BCM/y) by 2014 according to Asia Pulse (June 30, 2006). Following suit with neighboring Turkmenistan, Uzbekistan raised gas export prices for Russia by 50 percent to $4.25 per MCF ($150 per MCM) in the second half of 2008 and for Tajikistan and Kyrgyzstan by 45 percent to $4.11 per MCF ($145 per MCM) in 2008. Unlike Turkmenistan, a high percentage of gas produced by Uzbekistan is used for domestic consumption. This averaged nearly 80 percent over the past decade. The country has the highest population in Central Asia - 27 million in 2007 - therefore export capabilities are limited.

Uzbekistan has signed several accords and PSAs with Russian and Asian companies. Soyuzneftegaz (Russia) signed a new 36-year PSA with Uzbekneftegaz in February 2007 and intends to invest $462 million for development of gas fields in the Ustyurt plateau region and the Southwest Gissar blocks. In February 2008, Lukoil, another Russian energy company, acquired a controlling interest in this PSA and targets 106 BCF/y (3 BCM/y) of production. Gazprom is getting more involved in revamping old fields in Uzbekistan and plans to boost natural gas exports from the country. Gazprom and Uzbekneftegaz signed an agreement on strategic cooperation in 2002 in which the Russian company plans to purchase long term Uzbek gas exports and participate in PSAs. In December 2006, Gazprom received exploration licenses from Uzbekneftegaz to develop 7 gas blocks with combined reserves of 35 TCF (1 TCM). Gazprom expects to invest $400 million by 2011 and $1.5 billion over the contract life. The companies will pump between 480 and 580 BCF/y (13.6 and 16.4 CM/y) of gas from the fields. In 2004, the two parties signed a $15 million, 15-year PSA to develop the Shakhpati field in northwestern Uzbekistan. The field has an estimated 272 BCF (7.7 BCM) of reserves. Lukoil, another Russian energy company, signed a 35-year, $3 billion PSA with Uzbekneftegas in June 2004 to develop the Khauzak and Kandym natural gas deposits, estimated to hold roughly 8 TCF (250 BCM) of natural gas. From 2011 the company hopes to begin producing around 210 Bcf/y (6 BCM/y).

Gas Surplus/ Deficit projection

The gas surplus/ deficit projection for Uzbekistan up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. The details calculated are shown in Table 4.16.

Uzbekistan (Reserves-283 MMSCMD)

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	131	147	171	198	229
Production	168	198	227	227	227
Export/Import	37	51	56	29	-3
Surplus/deficit	152	136	113	85	54

(All Figs are in MMSCMD)

Table:4.16 Uzbekistan - Projection of Surplus/ Deficit of Gas

4.3.9 INDIA

The Indian economy continues to show impressive economic growth. The country's real gross domestic product (GDP) grew at an impressive rate of 9.1 percent during the first half of fiscal 2006 (April -September 2006), after growing by 8.7 percent in fiscal 2005. Together with the country's impressive growth, India has also become a significant consumer of energy resources. Gas consumption in India has outpaced other countries in Asia. Its share in the country's energy basket has increased from 6.4 percent in 1997 to 8.6 percent in 2007. Steep growth in demand coupled with insufficient indigenous production has triggered the demand for LNG. The share of LNG in India's gas consumption mix has jumped from marginal levels in 2002 to 22 percent in 2007. Recent gas finds and the fact that only 20 percent of India's sedimentary basins have been well explored instill confidence that indigenous gas supply could increase in the short to medium term.

A grouping of state companies under the umbrella of Petronet LNG has started constructing a LNG terminal capable of receiving 5 million tons of fuel per year. This is now being upgraded to 10 MTA. In addition to LNG, India now hopes to see a gas import pipeline built from Bangladesh that would deliver as much as 500 million cubic feet per day to New Delhi -assuming political opposition inside Bangladesh can be overcome. Pipelines from Turkmenistan or Iran to India via Pakistan have also been proposed. Even as both projects IPI and TAPI are being discussed by all participant countries, India is also looking east beyond Bangladesh to Myanmar as another possible alternative source of pipeline gas.

The level of economic performance and fast growing population has made India one of the largest consumers of commercial energy (coal, oil, gas and electricity).

Energy Policy

The Indian government encourages further gas consumption so as to reduce pollution and the dependence on imported oil. However, bureaucratic, regulatory, and political impediments have hampered efforts to implement this, both on the supply and demand ends. Some reforms have been enacted. GAIL and ONGC have both been partially privatized, although. GAIL is still 67 percent state-owned and only a small part of ONGC's equity has been sold, and that mainly to other state oil companies. The government has allowed domestic and foreign private companies into exploration and production under production-sharing contracts and to have up to 60 percent equity in joint ventures with ONGC and OIL. Foreign and Indian private firms also are allowed to build LNG terminals and construct pipelines.

To give a major boost to natural gas exploration and ensure private sector participation, the Government of India announced in 1998 the New Exploration Licensing Policy (NELP) in oil and gas exploration. The policy allows 100 per cent foreign equity, streamlined permitting processes, and most significantly, grants producers the right to sell gas at market prices. The first significant find by a private sector company was made by Reliance Industries in the Krishna Godavari basin off Andhra Pradesh coast in 2002 with reserves estimated near 12 TCF, The find was expected to yield a projected output of 40 million standard cubic metres per day (MMSCMD) by the end of the decade. The second major find, made by the Gujarat State Petroleum Corporation in 2005, is the largest gas field ever found in India. This 20 TCF field is also in the Krishna Godavari basin and will have a projected output of 80 MMSCMD by 2010. The NELP and later 'India Hydrocarbon Vision - 2025' shows the Government of India's urge to tap the vast unexplored or poorly-explored areas with substantial yet-to-be-established hydrocarbon resource base and fill the widening gap between demand and supply.

By 2020, India needs a total of 115 to 135 BCM of natural gas supply i.e. 70 to 90 BCM of additional supply to meet expected demand. This is over the 35 BCM of indigenous production and 10 BCM of LNG in 2007. The status of current projects indicates that indigenous production would increase to 55 BCM by 2012. But in the longer term, indigenous gas alone may not be able to fulfill the India's consumption needs. Pipelines could play an important role in bridging this gap. The Iran-Pakistan-India (IPI) project (32 BCM) and Myanmar-India pipeline (12 BCM) could provide 40 to 45 BCM of gas. If pipeline projects are delayed and enough is not done to accelerate indigenous production, India will need LNG imports to the tune of 40 to 90 BCM by 2020.

Primary Energy Mix and Sectoral Analysis

The consumption of traditional fuels grew at the rate of 2.7 per cent, from 185 MTOE (million tonnes of oil equivalent) in 1980-81 to 331 MTOE in 2002-03. Coal consumption increased at the rate of 5.8 percent from 109 million tonnes to 358 million tonnes; oil consumption increased at the rate of 6.4 per cent from 31 million tonnes to 111 million tonnes; natural gas consumption increased at the rate of 15.6 percent from 1522 million cubic meters to 29,718 million cubic meters; hydroelectricity consumption increased at the rate of 3.2 per cent from 46,557 million kwh to 84,619 kwh; nuclear electricity consumption grew at the rate of 9 per cent from 3,001 million kwh to 21,273 million kwh, and electricity consumption from renewable sources increased from 69 million kwh to 16,122 million kwh over the same period.

Table 4.17 shows the distribution of growth in total primary energy demand in various sectors like Power, Industry, Transport and other sectors.

(Source : World Energy Outlook, 2006)

INDIA								
	Energy Demand(MTOE)			Share (%)			Growth(% p.a)	
	2005	2015	2030	2005	2015	2030	2005-2015	2005-2030
Total primary energy demand	537	770	1299	100	100	100	3.7	3.6
Coal	208	330	620	39	43	48	4.7	4.5
oil	129	188	328	24	24	25	3.9	3.8
Gas	29	48	93	5	6	7	5.2	4.8
Nuclear	5	16	33	1	2	3	13.2	8.3
Hydro	9	13	22	2	2	2	4.4	3.9
Biomass & waste	158	171	194	29	22	15	0.8	0.8
Other renewables	1	4	9	0	1	1	23.8	11.7
Power generation	191	312	583	100	100	100	5	4.6
Coal	156	240	444	81	77	76	4.4	4.3
oil	8	10	8	4	3	1	1.5	0
Gas	13	27	52	7	8	9	7.5	5.8
Nuclear	5	16	33	2	5	6	13.2	8.3
Hydro	9	13	22	4	4	4	4.4	3.9

Biomass & waste	1	3	17	1	1	3	11.9	11.5
Other renewable	1	4	7	0	1	1	22.5	11.1
Industry	99	157	271	100	100	100	4.7	4.1
Coal	29	55	111	30	35	41	6.4	5.4
Oil	19	27	38	19	17	14	3.6	2.7
Gas	5	7	10	5	4	4	3	2.7
Electricity	18	39	83	18	25	31	7.9	6.3
Heat	0	0	0	0	0	0	n/a	n/a
Biomass & waste	27	29	30	28	19	11	0.7	0.4
Other renewable	0	0	0	0	0	0	n/a	n/a
Transport	37	66	162	100	100	100	6	6.1
Oil	35	63	154	96	94	95	5.9	6.1
Biofuel	0	1	2	0	1	1	55.7	22.9
other fuels	2	3	7	4	4	4	6.4	5.9
Residential, services & agriculture	183	219	295	100	100	100	1.8	1.9
Coal	6	6	6	3	3	2	-0.2	0
Oil	27	35	45	15	16	15	2.6	2.1
Gas	1	2	6	0	1	2	7.5	8.5
Electricity	20	39	92	11	18	31	6.8	6.3
Heat	0	0	0	0	0	0	n/a	n/a
Biomass & waste	130	138	146	71	63	49	0.6	0.5
Other renewable	0	0	1	0	0	0	n/a	n/a
Electricity generation (TWH)	699	1322	2774	100	100	100	6.6	5.7
Coal	480	889	1958	69	67	71	6.4	5.8
Oil	31	35	31	4	3	1	1.2	0
Gas	62	133	292	9	10	11	7.9	6.4
Nuclear	17	60	128	2	5	5	13.2	8.3
Hydro	100	154	258	14	12	9	4.4	3.9
Biomass & waste	2	6	29	0	0	1	11.9	11.5
Other renewable	6	43	78	1	3	3	47.5	45.4

Table: 4.17 India- Sectoral Energy Analysis

In power generation, coal is the main fuel use with 81 percent weightage as compared to gas, which has 0.06 percent weightage. Growth rate of gas is 7.4 percent as compared to 4.4 percent for coal. Gas demand in India's power sector is increasing today because of its benefits over other fuel.

Coal meets the maximum energy demand i.e. 29.29 percent of total energy requirement of the industrial sector in India. The demand for coal is growing at 6.7 percent, followed by oil at 19 percent, with a growth rate of 3.6 percent.

Oil is the main fuel in transport sector with a growth rate of 6.1%. In this sector, biomass and waste meet the major portion of energy demand i.e 130 MTOE out of total 183 MTOE needed, at growth rate of 0.5 percent. Oil also meets demand of 27 MTOE, with a growth rate of 2.6 percent.

Coal is the major producer of electricity. It generates approximate 70 percent of the total electricity, at a growth rate of 6.4 percent. In future, gas and nuclear energy could substitute coal, which at present produce electricity at a growth rate of 7.9 and 13.2 percent.

India's primary energy demand mix for 2006 is shown in Exhibit 4.17.

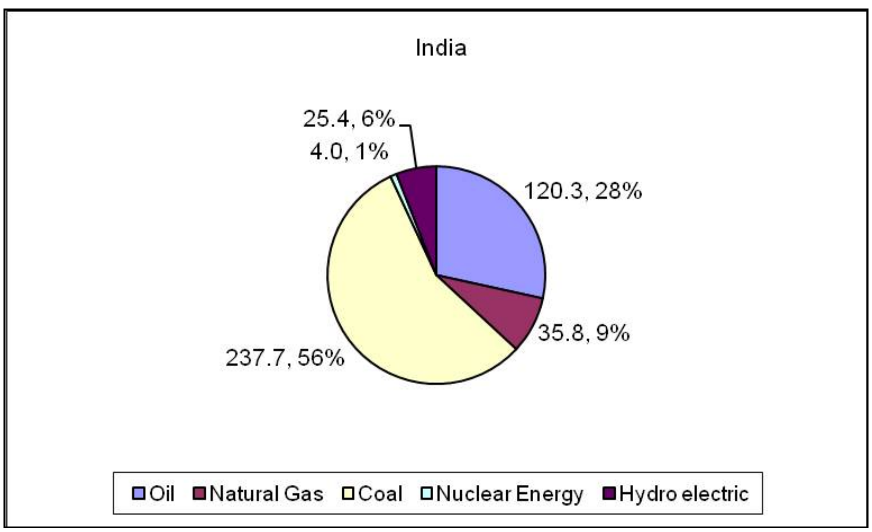

Exhibit: 4.17 India- Primary Energy Demand for 2006 (MTOE)

Natural Gas Reserves and Production

According to OGJ, India had 38 trillion cubic feet (TCF) of proven natural gas reserves as on January 2007. The bulk of India's natural gas production comes from western offshore regions, especially the Mumbai High complex. Onshore fields in Assam, Andhra Pradesh, and Gujarat states are also major producers of natural gas. According to EIA data, India produced 996 billion cubic feet (BCF) of natural gas in 2004.

India imports small amounts of natural gas. In 2004, India consumed 1,089 BCF of natural gas, the first year in which the country showed net natural gas imports. During 2004, India imported 93 BCF of liquefied natural gas (LNG) from Qatar. There have been several large natural gas finds in India over the last five years, predominantly in the offshore Bay of Bengal. In December 2006, ONGC announced that it had found an estimated 21 to 22 TCF of natural gas at the KG-DOWN-98/2 block in the Krishna Godavari basin, off the coast of Andhra Pradesh. On the same day, ONGC announced another find in the Mahanadi basin off the coast of Orissa state, with an estimated 3 to 4 TCF in place. Neither of these finds has been certified, but could potentially raise India's natural gas reserve levels significantly. The discoveries also fit into the recent trend of large upstream developments in the Bay of Bengal, especially in the Krishna Godavari basin. State-owned Gujarat State Petroleum Corporation (GSPC) holds an estimated 20 TCF of natural gas reserves in place at KG-OSN-2001/3 block in the Krishna Godavari area.

Reliance Industries recently secured government approval for the commercial development of the D-6 block in Krishna Godavari basin, which holds 9 TCF of recoverable natural gas reserves (14.5 TCF total reserves in place). Under the development plan for the D-6 block, Reliance and its equity partner Niko resources will spend $5.2 billion to bring the first natural gas to the market in 2009. At its peak, the D-6 block is expected to supply 2.8 BCF/d of natural gas, which would more than double the country's current production level. Despite these large finds, most analysts expect demand for natural gas in India to outstrip new supply in the years ahead. Indian natural gas consumption has risen faster than any other fuel over the last five years. ONGC has worked to maximize its recovery rate at the Mumbai High structure, which supplies the bulk of the country's natural gas at present. BG International and Reliance Industries are also jointly working to expand production at the Tapti, Panna, and Mukti fields in the Mumbai High basin. The companies currently produce 300 million cubic feet per day (MMCF/d) at these three fields, although they have not announced a target production level for the expanded project plans. Key gas fields of India are shown in Table 4.18

Key Gas Fields			
S.No.	**Location**	**Name**	**Comments**
1	Offshore, Maharashtra State	Bombay High North and South	Oil field that account for roughly 45% of all gas produce in India
2	Onshore, Gujarat State	Tapti	31 BCM reserves
3	Offshore, Krishna Godavari basin	Block D6	2003 find reserves estimated vary from 243 BCM - 397 BCM
4	Offshore, Bay of Bengal, Orissa State	Dhirubhai 9, 10 and 11	2004 find initial reserves estimated at 28 BCM but as high as 142 BCM

Table:4.18 India- Key Gas Fields

Gas Surplus/ Deficit Projection

The gas surplus/ deficit projection for India up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. The details calculated are shown in Table 4.19.

INDIA (Reserves-164 MMSCMD)

Year	**2006**	**2010**	**2015**	**2020**	**2025**
Demand	120	151	202	269	358
Production	96	114	131	131	131
Export/Import	-24	-37	-71	-138	-227
Surplus/deficit	43	28	-38	-105	-194

(All Figs are in MMSCMD)

Table:4.19 India- Projection of Surplus/ Deficit of Gas

4.3.10 PAKISTAN

Pakistan's economy has recovered from years of sluggishness caused primarily by droughts, with growth experienced in agriculture, industry and service sectors. In fiscal year (FY) 2004/2005 (ending in June), Pakistan achieved gross domestic product (GDP) growth of 8.4 percent and in 2005/2006 the country had GDP growth of 6.6 percent.

Pakistan's economy is undergoing significant changes since 1998-99; the improvements made in the macroeconomic indicators are, in particular, noteworthy. With expansion in economy the demand in energy will also increase. Government of Pakistan's (GoP) Medium Term Development Framework (MTDF) projects the growth in the demand of electricity, petroleum products, natural gas and coal at an average annual rate of 8.4 percent, 4.3 percent, 7.6 percent, 18.9 percent respectively. Although both the demand and supply of energy has been increasing for the last decade and a half, the per capita consumption of energy in Pakistan remains low. As compared to their counterparts in Malaysia and China where per capita consumption of energy stands at 92 MBTU and 34MBTU respectively, the per capita consumption in Pakistan is 14 MBTU.

Energy Policy

Pakistan’s Ministry of Petroleum and Natural Resources regulates the country’s oil sector. The Ministry grants oil concessions by open tender and by private negotiation. To encourage oil sector investment, the Ministry offers various tax and royalty payment incentives to oil companies. Pakistan’s three largest national oil companies (NOCs), include the Oil and Gas Development Corporation Limited (OGDCL), Pakistan Petroleum Limited (PPL) and Pakistan State Oil (PSO). All three operate under joint ventures and partnerships with various international oil companies (IOCs) and other domestic firms. Major IOCs operating in Pakistan include BP (UK), Eni (Italy), OMV (Austria), Orient Petroleum Inc. (OPI, Canada), Petronas (Malaysia) and Tullow (Ireland).

In response to conditions laid down by lenders, such as the IMF and the World Bank, Pakistan continues to strive for privatization of its state-owned companies. For instance, the government has on offer a 51 percent stake in PPL, as well as a 54 percent stake in PSO. PPL owns the Sui fields in Balochistan, as well as exploration interests in 22 blocks, while PSO holds a majority share in the domestic diesel fuel market with more than 3,800 retail outlets. In November 2006, Pakistan planned to have a share issue from OGDCL for the equivalent of 15 percent of the NOCs capitalization. Five percent of the company was earlier in November 2003 divested in an initial public offering (IPO).

Over the next several years Pakistan hopes to reap significant revenues from these privatizations. BP is the largest oil producer in Pakistan, with production averaging approximately 30,000 BBL/d. The oil major operates 43 fields and more than 100 wells throughout the country. OGCDL is Pakistan's second-largest oil producer, with average production at 25,000 BBL/d. While there is no prospect for Pakistan to reach self-sufficiency in oil, the government has encouraged private (including foreign) firms to develop domestic production capacity. In 2005, NOCs and IOCs drilled a total of 29 onshore development wells in Pakistan. BP led the development by drilling ten wells in its Lower Indus Basin acreage, while ODCGL drilled nine wells, with the majority being on its acreage in the Middle Indus Basin. PPL expanded its interests in 2005 by drilling offshore at the Pasni X2 shallow water field. It was the first time a Pakistani oil company had explored offshore.

Historically, Pakistan has held few large licensing rounds, and instead, has conducted private negotiations for acreage between individual companies and the Ministry of Petroleum and Natural Resources. In February 2006, Pakistan opened a rare licensing round offering nine onshore and offshore blocks. From the blocks offered, the Pakistani government awarded OGDCL three exploration licenses in the southern Sindh and Balochistan provinces. The licenses cover the Tegani, Thal and Than Beg Blocks and OGDCL has committed to conduct geological surveys and drilling of four exploration wells in the blocks. In June 2006, the government awarded POL an exploration license for the Kirthar Block in southern Pakistan. In July 2006, Pakistan awarded BP three blocks (U, V, and W) in the offshore Indus Delta region.

Primary Energy Mix

Pakistan's total primary energy supply in tones, equivalent of oil (TOE) in the fiscal year 2003-04, stood at 50.8 million TOE. The primary energy supply has seen a constant increase since 2001. It increased by 4.4 per cent from 2001-02 to 2002-03, and by another 8 per cent from 2002-03 to 2003-04.

Exhibit 4.18 shows the share of different energy resources in the primary energy mix supplies. The patterns of energy consumption have also registered an upward trend.

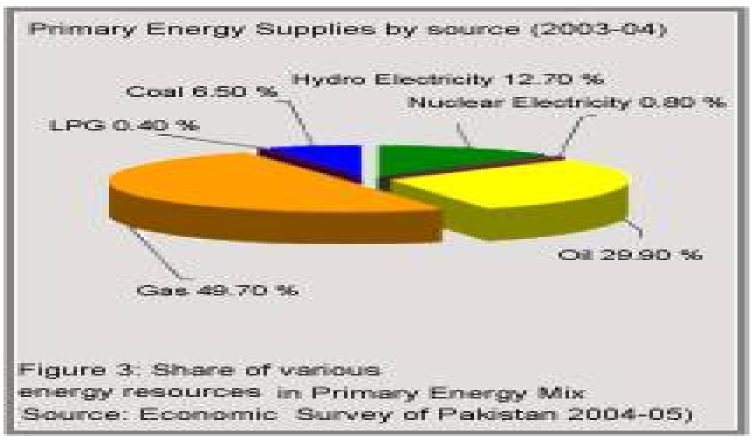

Exhibit. 4.18 Pakistan- Primary Energy Mix

According to the latest economic survey, in the past 14 years from 1990-99 to 2003-04, the consumption of petroleum products, natural gas, electricity and coal increased by an annual average rate of 2.5 percent, 4.9 percent, 5.1 percent and 5.2 percent, respectively. However, a major change in consumption pattern was registered in oil. The use of oil has reduced since 2001, particularly in the cement industry and power generation, because the cement industry has shifted to natural gas and the power generation sector is increasingly using gas. Similarly, the consumption of various petroleum products in households and agriculture registered marked a decline of 16.2 and 16.8 percent, respectively. This is primarily because of the availability of cheaper fuels like LPG and natural gas. However, the consumption of petroleum products has increased in transportation, industrial and other government sectors. In the last 14 years, the transport sector saw the largest use of petroleum products with a share of 48.7 percent. The share of power sector, industry, households, other government sectors and agriculture stood at 31 percent, 12.1 percent, 3.8 percent 2.5 percent and 1.5 percent respectively.

Sector wise natural gas consumption from 1990 to 2004 is shown in Table 4.20.

Power sector	35.40%
Fertilizer	23.40%
Industrial	18.90%
Household	17.60%
Commercial	2.80%
Cement	1.50%

Table:4.20 Pakistan- Natural Gas Consumption 1990-2004

Pakistan's primary energy demand mix for 2006 is shown in Exhibit 4.19.

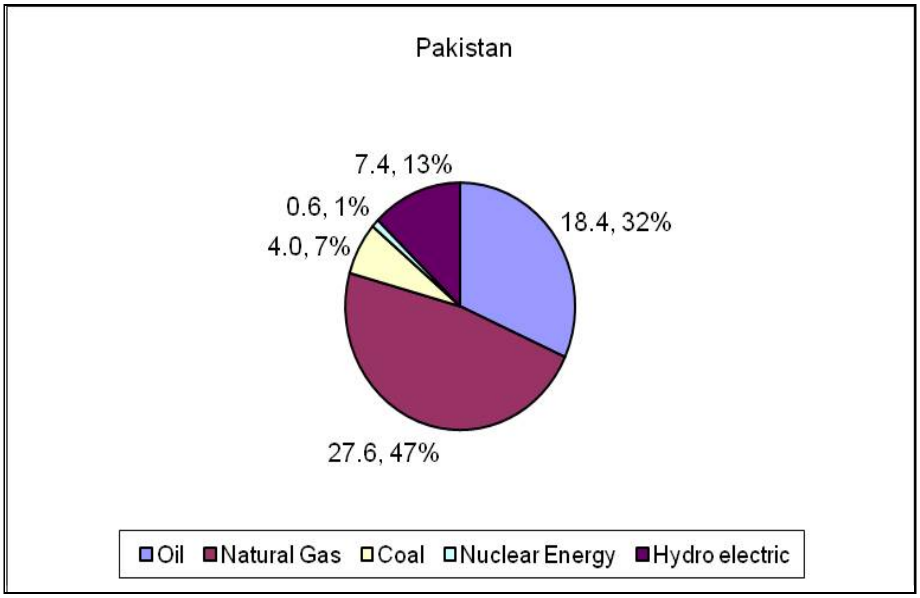

Exhibit:4.19 Pakistan- Primary Energy Demand for 2006 (MTOE

Natural Gas Reserves and Production

According to OGJ, Pakistan had 28 trillion cubic feet (TCF) of proven natural gas reserves in 2006.The bulk of these reserves are located in the southern half of Pakistan. In 2004, Pakistan produced and consumed 968 billion cubic feet (Bcf). In light of the current onshore exploration activities and resource outlook, the Pakistani government expects minor increases in natural gas production in the short-term. However, natural gas production is expected to decline over the next 15-25 years, while natural gas demand is expected to be increase. The Pakistani government is currently developing plans to import additional natural gas in order to satisfy increasing demand. According to the Pakistan Energy Yearbook, natural gas is currently the country's largest energy source, making up 50 percent of Pakistan's energy mix in FY 2004/2005. Pakistan's largest natural gas production occurs at the Sui field, which is located in the Southern Indus Basin. PPL operates Sui field, with production averaging 655 MMCF/d.

Additional producing fields include Mari (446 MMCF/d), Sawan (366 MMCF/d), and Bhit (316 MMCF/d). In 2005, BHP Billiton signed a Gas Sales and Purchase Agreement (GSPA), in which the company will supply an additional 150 million cubic feet per day (MMCF/d) of natural gas from its Zamzama field. BHP Billiton will complete phase II development of Zamzama in the third quarter of 2007. Petronas brought its Rehmat field online in March 2005. The field produces an estimated 30 MMCF/d, which is sold to consumers in Pakistan's southern Sindh province. In the past few years, the country discovered seven new natural gas fields. The Pakistani government expects the development of these new fields to add an additional 1 Bcf/d to Pakistan's natural gas production.

Key gas fields of Pakistan are given in Table 4.21.

Key Gas Fields		
Location	**Name**	**Comments**
Sindh province	Mari	6 Tcf - 7 TCF of reserves
Thar desert, Sindh province	Kadanwari	80 MMCF/d
Sindh province	Zamzama	248 MMCF/d with potential to reach 380 MMCF/d over 20 years
Sindh province	Sui	650 MMCF/d
Sindh province	Adhi and Kandkhot	120 MMCF/d
Southern Sindh province	Badin	200 MMCF/d
Sindh province	Qadirpur	3.4 TCF
Sawan Block, Sindh province	Sawan	1.46 TCF
Kirthar block, Sindh province	Bhit	633 Bcf of reserves and production capacity of 316 MMCF/d

Table:4.21 Pakistan- Key Gas Fields

Gas Surplus/ Deficit projection

The gas surplus/ deficit projection for Pakistan up to 2025 is calculated based on the actual status of 2006 on demand/ production and the estimated reserve. The details calculated are shown in Table 4.22.

Pakistan (Reserves-121 MMSCMD)

Year	2006	2010	2015	2020	2025
Demand	93	105	121	141	163
Production	93	97	97	97	97
Export/Import	0	-8	-24	-44	-66
Surplus/deficit	28	16	0	-20	-42

(All Figs are in MMSCMD)

Table:4.22 Pakistan- Projection of Surplus/ Deficit of Gas

4.4 ROLE OF NATURAL GAS IN DEVELOPMENT OF ASIAN COUNTRIES

Primary Energy Mix & Sectoral Analysis – Asia (MTOE)

Primary Energy mix of Asia is shown in Table 4.23. Coal dominates the primary energy mix in the Asia Pacific region, followed by oil. While primary energy estimated consumption grew by a handsome 4.3% from 2005 to 2015, coal estimated increased its share in the energy mix from 47% in 2005 to 51% in 2015, driven primarily by increase in reported Chinese coal consumption. Consequently, oil will maintain its share at 24% from 2005 to 2015 but natural gas share will increase from 7% to 8% from 2005 to 2015.

Source: Word Energy Outlook 2007

Developing Asia								
	Energy demand (MTOE)			Share(%)			Growth (% p.a)	
	2005	2015	2030	2005	2015	2030	2005-2015	2005-2030
Total primary energy demand	3027	4615	6427	100	100	100	4.3	3.1
Coal	1423	2368	3254	47	51	51	5.2	3.4
Oil	728	1086	1594	24	24	25	4.1	3.2
Gas	216	371	586	7	8	9	5.6	4.1
Nuclear	29	66	119	1	1	2	8.3	5.7
Hydro	53	91	133	2	2	2	5.5	3.7
Biomass & waste	560	593	658	18	13	10	0.6	0.6
Other renewable	18	41	83	1	1	1	8.7	6.3

Power generation	1074	1844	2799	100	100	100	5.6	3.9
Coal	827	1420	2098	77	77	75	5.6	3.8
Oil	53	61	48	5	3	2	1.3	-0.4
Gas	90	156	260	8	8	9	5.7	4.4
Nuclear	29	66	119	3	4	4	8.3	5.7
Hydro	53	91	133	5	5	5	5.5	3.7
Biomass & waste	6	17	76	1	1	310.2	10.5	
Other renewable	15	34	65	1	2	2	8.5	6.1
Other energy sector	339	575	805	100	100	100	5.4	3.5
Electricity generation (TWH)	4143	8233	13480	100	100	100	7.1	4.8
Coal	2730	5701	9364	66	69	69	7.6	5.1
Oil	214	243	194	5	3	1	1.3	-0.4
Gas	428	804	1391	10	10	10	6.5	4.8
Nuclear	113	252	456	3	3	3	8.3	5.7
Hydro	617	1057	1547	15	13	11	5.5	3.7
Biomass & waste	16	44	204	0	1	2	28.5	14.6
Other renewable	25	132	324	0	1	2	35.8	25.7

Table: 4.23 Asia- Sectoral Energy Analysis

In the Asia Pacific region, coal dominates as power generation fuel from 2005 to 2015, maintaining its share at 77 percent, with growth rate at 5.6 percent during this period. This is followed by gas which maintains a share 8 percent with growth rate of 5.7 percent from 2005 to 2015. While growth rate of oil consumption in power sector is 1.3 percent from 2005 to 2015, its share decreases from 5 percent to 3 percent during this period. The use of nuclear in power sector will increase at 8.3 percent and its share increase from 3 to 4 percent of total fuel consumed in the power sector from 2005 to 2015.

In electricity generation, the use of coal will increase at the rate of 7.1 percent, and its share will increase from 66 percent to 69percent of total fuel consumed from 2005 to 2015. The use of gas will increase at the rate of 6.5 percent and nuclear energy consumption at the rate of 8 percent, while maintaining its share at 10 percent and 3 percent respectively from 2005 to 2015.

Measures for Increasing Use of Natural Gas

Increasing flow constraints, rising prices, and intensifying competition will pose significant challenges for the gas industry. Stakeholders will need to act on multiple fronts.

1. Governments and Regulators in Gas-Short Countries

On the domestic front governments and regulators need to:

- *Make gas a meaningful part of the power portfolio*

Despite short term flow constraints, emphasis on natural gas as a key constituent in the country's power generation mix is a must. More so as natural gas has distinct advantages, unlike coal and oil.

- *Ensure attractiveness for suppliers*

To attract imports and encourage domestic exploration and production, it is essential for governments to allow domestic prices to align with global prices. At a minimum, they should encourage domestic users to pay international prices for gas. This will help develop local gas markets and infrastructure. In addition, they should craft energy policies that provide attractive returns on investments and in effect enhance investor confidence. This calls for supporting a competitive price regime, and articulating a minimum threshold for capacity utilization for a given duration.

- *Create demand centers*

Regulators need to encourage the formation of consortia and industrial parks that import bulk supplies.

On the International front governments must,

- *Collaborate with resource-rich countries*

Increased collaboration with targeted gas-rich countries is imperative to ensure that supply is augmented. Governments in gas-short countries are increasingly bypassing International Oil Companies (IOCs) and working directly with governments of gas-rich countries and their national oil companies.

- *Support establishment of an Asian gas trading mechanism*

Unlike Europe and North America, Asia lacks financial tools to manage price and volume risks resulting from gas trades. Seeking agreement on a regional gas price index and ensuring liquidity will be a good start. However, due to the significant differences across various Asian countries, making this work will require significant international collaboration and effort to build trust.

2. Natural Gas Buyers In Gas-Short Countries

In order to secure additional supplies at competitive prices, buyers in gas-short countries should:

- Adopt creative approaches to seek gas supply.
- Work with regulators and government to facilitate gas supply:
- Companies in gas-short countries must lobby with their governments and regulators to ensure infrastructure investments are made to attract supply.

3. Resources Owners and Providers

To play a strategic role in developing the global gas market, resource owners and providers must:

- *Provide clarity on national energy policies*

Resource-rich countries need to outline their future consumption requirements and subsequent export potential. This will help streamline contracting between the resource owners and gas buyers.

- *Remove bottlenecks in projects*

Continuous delays in infrastructure build-outs will ultimately undermine the market. In the current scenario, adopting the mindset “supply creates its own demand”, is appropriate. Execution of large-scale infrastructure projects e.g. pipelines and terminals should be expedited.

Gas will fail to gain its rightful place in the world’s energy basket if any of this is not done.

4.5 CONCLUSION

Asia’s available gas scenario in MMSCMD form has been considered in the techno-commercial feasibility study of AGG, which will be dealt in the subsequent chapter. The proven reserve of various countries is taken from *BP Statistics Review 2007*. These reserves in TCM are converted into MMSCMD by considering 20 years and 330 days as operating time, as MMSCMD is the unit extensively followed in natural gas pipeline industry across Asia.

Based on the data collected on gas availability and demand of each country, the gas supply/ demand is derived as shown in Table 4.24.

S.No.	**Country**	**Reserve (Supply)**	**RPR Ratio**	**Consumption of 2006**	**Projected Demand up to 2025**	**Demand/ supply gap by 2025**	**Remarks**
		(A)	**(B)**	**(C)**	**D= $Cx1.03^{19}$**	**(A – D)**	
		MMSCMD	No.	MMSCMD	MMSCMD	MMSCMD	
1	Russian Federation	7220	77.8	1309	2296	4924	Surplus
2	Iran	4262	267.9	319	559	3704	Surplus
3	Qatar	3843	512.3	59	104	3739	Surplus
4	Kazakhstan	455	125.4	61	108	347	Surplus
5	Turkmenistan	433	46	57	101	333	Surplus
6	Indonesia	398	35.6	120	210	188	Surplus
7	Malaysia	376	41.2	122	214	162	Surplus
8	China	371	41.8	168	588	-217	Deficit
9	Uzbekistan	283	33.7	131	229	54	Surplus
10	Kuwait	270	70.8	39	69	201	Surplus
11	India	164	33.9	120	358	-194	Deficit
12	Pakistan	121	26	93	163	-42	Deficit
13	Bangladesh	67	28.6	46	81	-14	Deficit
14	Myanmar	82	40.1	13	22	60	Surplus
15	Thailand	45	12.4	98	172	-127	Deficit
16	Japan	16	7	286	502	-486	Deficit

Table: 4.24 Projected scenario of gas demand / supply of AGG countries

Assumptions in above calculations are based on:

- Considering 20 years and 1 year = 330 days
- RPR is Reserve to Production ratio.
- Consumption: Considering 3 percent growth except China and India at 6.8 percent and 5.9 percent respectively
- Surplus: (Reserve – Consumption) of 20 years considering 3 percent growth except China and India at 6.8 percent and 5.9 percent respectively.

In this study, the following gas fields are proposed to be available for supply in AGG:

1. Assaluyeh field- Iran 165 MMSCMD
2. Daulatabad field- Turkmenistan 150 MMSCMD
3. Uzbek Border field- Turkmenisatn 50 MMSCMD
4. Karachaganak field-Kazakhstan 100 MMSCMD
5. Caspian Block-Kazakhstan 50 MMSCMD
6. Chittagong- Bangladesh 20 MMSCMD
7. Sitwe- Myanmar 30 MMSCMD

TOTAL **565 MMSCMD**

Table 4.25 shows the % of gas proposed to be utilized from gas surplus countries in the AGG to meet the demand of gas short countries.

S.No.	Gas surplus countries	Net Surplus (2025)	Export (2006)	Unutilized gas	Used for AGG	% of utilization by AGG
		A	B	C=A-B	D	E=D/C*100
1	Russian Federation	4924	546	4378	0	0
2	Iran	3704	0	3704	165	4.50%
3	Qatar	3739	91	3648	0	0
4	Kazakhstan	347	11	336	150	45%
5	Turkmenistan	333	130	203	200	98.50%
6	Indonesia	188	104	84	0	0
7	Malaysia	162	60	102	0	0
8	Uzbekistan	54	37	17	0	0
9	Myanmar	60	0	60	30	50%
10	Bangladesh				20	
	TOTAL				**565**	

(in MMSCMD)

Table: 4.25 % Utilization of available gas by AGG

As noted in Table 4.25, 200 MMSCMD of gas is proposed to be tapped from Turkmenistan which is almost 98 percent, considering the possible availability of more gas from its unexplored gas reserves.

From the study, it clearly indicates that by 2025 the gas demand in growing Asian economies will increase, and urgent action will be required for continuous availability of gas in Asian demand centers. Actions will be required for supplementing the gas deficit countries by connecting them with countries having surplus gas so that gas availability is ensured throughout the Asian countries, in order to have sustained growth in different sectors. It can only be done by connecting all these countries through a cross border pipeline.