

Natural Gas in China

Market evolution and strategy

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Nobuyuki Higashi is a gas analyst in the International Energy Agency (IEA). The views expressed in this Working Paper are those of the author and do not necessarily represent the views or policy of the IEA or of its individual member countries. This paper is a work in progress, designed to elicit further discussion and debate. Comments should be directed to the author: nobuyuki.higashi@iea.org.

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1. Introduction

In 2007, China's natural gas consumption increased by 23.8% and attained 69.5 billion cubic metres (bcm) (NBS 2008).¹ Thanks to this rapid increase, China became one of the world's top 10 countries in terms of natural gas consumption. Moreover, according to the IEA's *World Energy Outlook 2008*, China will become the top natural gas consuming country in the Asia-Pacific region, overtaking Japan by 2015.² Until the start of liquefied natural gas (LNG) imports in 2006, China was self-sufficient in terms of natural gas. Although China has accelerated the domestic production of natural gas, which increased by 18.3% and attained 69.2 bcm in 2007, its import dependence is expected to increase rapidly due to rising gas demand. The penetration of city gas, together with the urbanisation of cities, the expansion of industrial use (including the petrochemicals industry and the power sector) have been the driving force behind this high-paced increase in demand. The government has enhanced natural gas use through policy and regulation, and by developing infrastructure. Despite the rapid increase in consumption, the share of natural gas in China's energy mix is still relatively low at 3.5%, while coal's share accounts for 69.5%. Natural gas consumption per capita amounted to only 53 cubic metres (m³) in 2007 while the world's average was about 460 m³. In order to promote the use of this "cleaner energy" as a substitute fuel for oil and coal, the government targeted to increase the share of natural gas in China's total primary energy consumption (TPEC) up to 10% by 2020,³ and has been leading the development of the natural gas market in the country.

It was only during the last decade that China's natural gas market showed such a notable expansion. Two main factors explain the lesser historical development of China's natural gas market: firstly, the natural gas business requires substantial investments for infrastructure; and secondly, natural gas is a far more expensive fuel than coal. At the end of 2004, the West-East Pipeline was completed at a length of 3 900 km. It was the first nationwide pipeline in China in order to transport inland domestic gas to the coastal cities. This pipeline opened a new stage in the evolution of China's natural gas market, from that of a local business to a nationwide business.

As far as the natural gas price is concerned, the Chinese government has been carefully considering setting a price level in order to promote natural gas use as a substitute for coal. Consequently, China's domestic prices for natural gas are far cheaper than international prices. In 2006, the first LNG regasification terminal in Guangdong was completed and opened the window of China's natural gas market onto the international market. But the impact of the differential between domestic prices and international prices has been limited until recently because China's import dependence ratio is still low. However, China's imports of natural gas are expected to increase rapidly, which implies that China's current price regime should be modified in the near future.

At present, China is constructing the second West-East Pipeline from the west end to the eastern and southern parts of China. Simultaneously, China is investing in the Central Asia Pipeline to transport 30 bcm of natural gas from Turkmenistan, via Uzbekistan and Kazakhstan. It is expected to connect to the second West-East Pipeline by the end of 2009. The total length of the main trunk line of both pipelines will be over 6 800 km. Two LNG terminals will open in 2009 and several other terminals are planned to start within a couple of years. Thus, China's natural gas market seems to be moving towards a second stage of evolution from a self-sufficient market to a market of high import dependency.

¹ National Bureau of Statistics, People's Republic of China

² According to the *World Energy Outlook 2008* Reference Scenario, natural gas consumption in 2015 is estimated to be 108 bcm in China and 90 bcm in Japan. In fact, recent trends indicate that China's energy consumption may exceed that of Japan, probably by 2010 (IEA 2008 a).

³ According to estimates made by a Chinese governmental research institute, the amount of natural gas should be around 250 bcm in order to realise 10% of TPEC in 2020.

However, the bleak situation of the global economic crisis is leading to considerable uncertainty regarding the path of gas demand in China. The expansion of China's presence as an importer will be one of the key factors in the international market of natural gas. China's demand-supply balance, its pricing policy and security strategy may directly affect the Asia-Pacific LNG market, and the European gas market indirectly, through pipeline gas imports from Central Asian countries. This report attempts to examine these issues.

2. Market Structure

2.1 Gas reserves

According to data provided by the China National Petroleum Corporation (CNPC) based on a national survey published in 2005, China's natural gas resources amounted to 56 trillion cubic metres (tcm) prospectively and 35 tcm geologically. The country's recoverable resources were estimated at 22 tcm, which was noted to have increased by 70% compared to the previous survey conducted in 1994.⁴ At the end of 2008, CNPC announced that China's total proven reserves amounted to 5.94 tcm, including 3.09 tcm of technically and economically producible reserves. In 2007, Cedigaz estimated that China's proven reserves amounted to 3.7 tcm, while the IEA estimated China's recoverable, proven and probable reserves from identified fields to amount to around 5.0 tcm (IEA 2007). In addition to conventional gas resources, the 2005 survey identified the huge potential of coalbed methane (CBM) as constituting 37 tcm of China's geological resources and 134.3 bcm of proven reserves, despite the fact that the current production level amounts to only 0.38 bcm per year.

China's major gas fields are located inland, in the western and north-central parts of the country. Historically, natural gas exploration has been closely linked to the development of oil fields, with the exception of the Sichuan gas field, which was, until recently, the largest non-associated gas field. As a result of accelerated exploration during the last decade, substantial new gas reserves have been discovered, and more than two-thirds of proven reserves in the country are currently classified as non-associated gas (Fridley 2008).

Three major basins – the Tarim Basin, the Ordos Basin and the Sichuan Basin – detain more than half of China's total proven reserves. The Ordos Basin, which extends across Shaanxi, Gansu, Ningxia and Inner Mongolia, has been developed since the late 1980s. The Sulige field in Inner Mongolia has been identified as holding China's largest proven reserves – 0.53 tcm. Before the discovery of the Sulige field, the Sichuan Basin was the largest national gas field (Kanbara 2002). The 2005 survey estimate the Tarim Basin in Xinjiang to have the largest recoverable resources, constituting 5.86 tcm. More recently (December 2008), CNPC announced the discovery of another large-scale gas field called Klameli in the Junggar Basin, in Xinjiang, with confirmed reserves of 100 bcm. The Junggar Basin is said to hold 2.5 tcm of total reserves, but less than 10% have been proved until now. With regard to China's offshore, major gas fields have been discovered in the East China Sea, the South China Sea and Bohai Bay. Recently, China National Offshore Oil Corporation (CNOOC) and Husky Energy, a Canadian oil company, announced the discovery of a deep-sea gas field in the South China Sea with 170 bcm of recoverable reserves.

⁴ Words such as “prospective” and “geological” are not defined in the data information.

Table 1. Natural gas resources by gas basin (tcm)

	Prospective	Geological	Recoverable
Tarim	11.3	8.9	5.9
Ordos	10.7	4.7	2.9
Sichuan	7.2	5.4	3.4
East China Sea	5.1	3.6	2.5
Qaidam	2.6	1.6	0.9
Yinggehai	2.3	1.3	0.8
Bohai Bay	2.1	1.1	0.6
Qiong Southeast	1.9	1.1	0.7
Songliao	1.8	1.4	0.8
Others	10.8	6.0	3.6
Total	55.9	35.0	22.0

Source: CNPC (latest resources survey in China, 2005).

Map 1. Gas resources in China



Source: CNPC.

2.2 Gas infrastructure

Until recently, natural gas consumption has been limited in China. Gas was primarily used as a local fuel or as a feedstock in chemical fertilizer. This was mainly due to the lack of infrastructure, particularly long-distance pipelines connecting inland gas fields to major consumer cities, mostly in the coastal areas in China. Even from the Sichuan Basin, which has a long history of natural gas production and has the most developed transmission infrastructure, natural gas was supplied only to neighboring provinces. Since the early 1990s, the government has promoted the construction of natural gas transport infrastructure and improved inter-regional connections between regional networks. After the significant discovery in the Ordos Basin in the late 1980s, the government decided to build the first major inter-regional pipeline, the Ordos (Shaanxi)-Beijing Pipeline, which was completed in 1997, at a length of 868 km and with a capacity of 3.6 bcm per year. Following this, the huge national project, the West-East Pipeline, was approved in 2000 and completed in December 2004. This pipeline delivers natural gas from the Tarim Basin in western China to Shanghai, the most emerging economic centre. Its main trunk line attained a length of 3 900 km and its capacity was initially 12 bcm which rose to 17 bcm by added compression. This gigantic pipeline opened a new stage in China's natural gas market, from local business to a nationwide business (Yan 2008).

In 2005, the second Ordos (Shaanxi)-Beijing Pipeline, with a capacity of 12 bcm, was completed and extended to a larger number of provinces. The government accelerated fuel diversification from coal to natural gas in the Beijing area to reduce air pollution for the Olympics in 2008. By the end of 2008, the total length of the national pipeline network in China attained 31 000 km, and several new pipeline projects are now under construction or planned. The construction of the second West-East pipeline transporting gas from Turkmenistan was launched in February 2008. The construction plan consists of two phases. The western part from Xingjian to Gansu – the north-central province – is expected to be completed by the end of 2009. The eastern part is due to be completed by 2012 to reach Guangdong,⁵ which is another emerging economic centre in southern China, but, which has been isolated from domestic gas pipelines until now. The second West-East Pipeline, through imported gas from Turkmenistan, will meet growing demand in two major economic zones in the coastal area: the Yangtze River Delta and the Pearl River Delta (see **Case studies** below). The total length of the main trunk line is 4 843 km with a capacity of 30 bcm per year. Three underground storages with a total working gas capacity of 2.5 bcm are planned to be built alongside the pipeline (Takehara 2008). CNPC has announced a total investment cost of CNY 142 billion (USD 20 billion). As examined later, this gigantic pipeline will bring about various evolutions and open the natural gas market in China to a second stage.

On the other hand, China National Petroleum & Chemical Corporation (Sinopec) is planning to build another two inter-regional pipelines from Sichuan to the Yangtze River Delta area (the Sichuan-East Pipeline) and to the Pearl River Delta (the Sichuan-South Pipeline). With regard to offshore gas fields, a sub-sea pipeline from the Yacheng gas field in the South China Sea to Hong Kong was constructed in 1996. In the Yangtze River Delta area, the first sub-sea pipeline was completed from the Pinghu gas field in the East China Sea to Shanghai in 1999.

Confronted by increasing gas demand in coastal areas since the late 1990s, the government planned to import LNG. The first LNG receiving terminal located in Guangdong was developed by CNOOC with a long-term sales and purchase agreement (SPA) with the Australian NWS project. The first cargo arrived at the terminal in 2006. The second terminal in Fujian was completed in 2008, and is awaiting first delivery from Indonesia's Tangguh project.⁶ Three additional terminals are now under construction in Shanghai,⁷ Jiangsu and Dalian.⁸ The total capacity of these five terminals amounts to 22 bcm (16.3 mtpa). Several other new projects are now being planned.

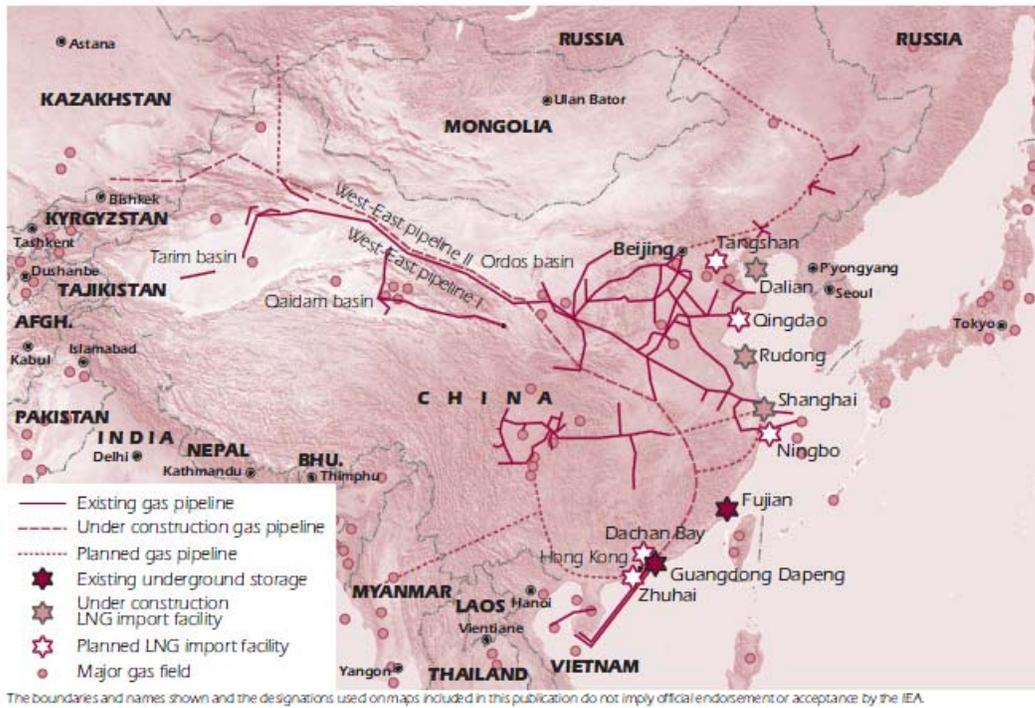
⁵ Recently, it was reported that the second West-East Pipeline will be extended to Hong Kong from Guangdong.

⁶ Fujian terminal started test operations and has been receiving spot cargoes since April 2008. In May 2009, media reported that commercial operations had started and the first cargo from Indonesia was delivered, but from the Bongtang plant rather than Tangguh.

⁷ Another small-scale LNG terminal is located in Shanghai, which was built by the Shenergy Group for the peak-saving storage of pipeline gas. It was reformed recently to receive small LNG vessels.

⁸ In March 2009, media reported that a feasibility study had been approved for CNPC to construct a new LNG terminal in Shenzhen, which will connect to the second West-East Pipeline.

Map 2. Natural Gas Infrastructure in China



Sources: Petroleum Economist, CNPC, IEA.

Table 2. LNG receiving terminals

	Location	Capacity (mtpa)	Open	Leading companies (share)
Existing	Guangdong*	3.7	2006	CNOOC (33%), BP (30%)
	Fujian	2.6	2008	CNOOC (55%)
Under construction	Shanghai	3.0	2009	CNOOC (45%), Shenergy (55%)
	Jiangsu	3.5	2011	CNPC (55%), Pacific Oil & Gas (35%)
	Dalian	3.5	2011	CNPC (75%)
Approved	Zhejiang	3.0		CNOOC (51%), Zhejiang Energy (29%)
	Qingdao	3.0		Sinopec
Planned	Zhuhai	3.5		CNOOC (25%), Guangdong Electric (35%)
	Shenzhen	3.5		CNPC (51%), CLP (24.5%)
	Caofeidian	3.5		CNPC
	Hainan			CNOOC

* The capacity will expand to 5.7 mtpa by 2011.

Sources: Media reports

2.3 Policy and regulation

In the decade prior to the start of the West-East Pipeline, China's natural gas consumption grew steadily by an average annual rate of 7%, then it jumped up and rapidly increased by above 20% per year from 2005 to 2007. However, natural gas is still a relatively minor fuel in China's energy mix and only detained a 3.5% share of total primary energy consumption (TPEC) in 2007, whereas the share of coal is 69.5%. The Chinese government has been promoting natural gas use in order to improve energy diversification and energy efficiency, and as a solution to environmental problems. Under the 10th Five-Year Plan (2001-05), the government set the target of raising natural gas use to 10% of the energy mix in 2020, which was basically reiterated in the 11th Five-Year Plan (2006-10).

In 2004, the State Council's Development Research Centre showed China's long-term policy for natural gas development in its report entitled *National Energy Policy and Strategy*, which strongly promoted using natural gas as a clean alternative to coal, primarily in the power and residential sectors. The 11th Five-Year Plan, which placed high priority on energy conservation and environmental protection in China, showed the picture of the energy balance in 2010, in which the natural gas share appears as 5.3%.⁹ According to estimates made by the Energy Research Center (ERI)¹⁰ in 2005, China's natural gas consumption will attain 250 bcm in 2020, assuming a 10% share in TPEC.

Table 3. Energy mix in China (coal equivalent calculation)

	TPEC (Mtce)	Coal (%)	Oil (%)	Natural gas (%)	Others (%)
2000	1 385.5	67.8	23.2	2.4	6.7
2007	2 655.8	69.5	19.7	3.5	7.3

Note: Emission of air pollutants (kg)			
	Coal	Fuel oil	Natural gas
CO ₂	6.2580	3.3320	2.1840
SO ₂	0.0506	0.0420	0.0002
NO _x	0.0218	0.0069	0.0026

Sources: China Energy Statistical Yearbook (CESY) 2008, CNPC.

In order to develop the natural gas market in China and particularly promote natural gas use as a substitute for coal and oil, the government has been carefully considering setting a price level. The power sector, in which coal is the dominant fuel, has been hesitant about using a more expensive fuel than coal. The residential sector in urban areas showed the ability to pay rather high prices and strong demand growth accompanied by the penetration of city gas. Industrial sectors can absorb relatively expensive natural gas as feedstock or the substitution fuel of oil. As for the chemical fertilizer industry, however, the government has allocated cheap gas with political and social consideration for farmers because natural gas is a key feedstock for fertilizer production.

Considering the situation in each sector, the government has basically determined the natural gas price on a cost-plus base, but with variations by sector. As a result, the natural gas prices in China have been remote from those in the international market. This price regime has been effective in developing China's natural gas market because natural gas was a self-sufficient fuel in the country until recently. Confronted by increasing gas demand, China began to import LNG in 2006, and is expected to increase imports of both LNG and pipeline gas, rapidly, from now on. However, international gas prices rose sharply, particularly in 2007-08, and the differential between domestic prices and international prices led to the emergence of several controversial situations in China. In industry, for example, many petrochemical plants used natural gas instead of oil, and sometimes produced too much because domestic natural gas prices were far cheaper than oil at that time. Natural gas demand in city gas increased thanks to the advantageous price of natural gas compared to LPG.

Faced with these situations, the government reset the allocation priority and the price level of natural gas for each sector. In August 2007, the NDRC issued a policy paper entitled *Policies on Natural Gas Use*, which categorised the priority of sectors and projects for natural gas use. Regarding prices, the policy paper called for the rationalisation of natural gas prices, in line with the prices of substitutable energy products. Thereafter, the government implemented the phased rise in domestic gas prices. However, increasing imports of natural gas is placing pressure on China's reform of the current price regime. (The details of price issues will be examined in a later section).

⁹ The 11th Five-Year Plan has assumed an annual growth rate of 7.5% in GDP during the period.

¹⁰ The governmental energy research institute under the National Development and Reform Commission (NDRC)

Table 4. New sector priority policy since 2007

	Residential sector	Industrial fuel	Chemical feedstock	Power sector
Priority	City residential Public facilities Natural gas vehicles			Combined (cool) heat and power system
Allowance	Centralised heating Decentralised heating Central air conditioning	Substitution projects of oil and LPG Substitution projects of coal with environmental and economical benefits Interruptible consumers	Low economic hydrogen projects Low economic nitrogenous fertilizer projects	Peak-shaving power generation in the area with sufficient supply
Confined			Expansion of ammonia projects Some chemical projects using methane	Non-essential load-power generation
Prohibited			Methanol projects	Base-load generation in the large-scale coal base area

Source: NDRC

2.4 Gas industry

As is the case with oil, China's upstream natural gas sector is dominated by three national oil companies (NOCs): CNPC, Sinopec and CNOOC. The birth of these NOCs took place in the 1980s during the process of economic reform in China. Before the reform, the government itself planned and developed the oil and gas sector under the Socialist regime. First of all, CNOOC was established in 1982 to manage offshore development, which seemed rather difficult to perform and required co-operation with foreign partners. Sinopec was established in 1983 to handle downstream refining. Finally, the responsibility of inland oil and gas production was delegated by the Ministry of Petroleum to the new NOC known as CNPC, in 1988 (Higashi 2006).

In 1998, the sector underwent a broad-scale restructuring: both CNPC and Sinopec began to handle entire segments from upstream to downstream but their mandates were geographically demarcated. All three companies were listed on the international stock exchanges in Hong Kong, New York and London in 2000,¹¹ and several western oil majors bought their stock. As far as the natural gas business is concerned, CNPC now holds approximately 75% of domestic gas resources and 80% of China's pipeline network (including major inter-provincial trunk lines). CNPC is also in charge of several major gas import projects, such as the Central Asia pipeline and LNG imports in Jiangsu and Dalian. Sinopec's core gas resources are located in Shandong and Sichuan, and it is also seeking LNG business opportunities. CNOOC provides offshore gas by pipeline from the South China Sea to Hong Kong, and from the East China Sea to Shanghai. Following its success on the Guangdong and Fujian projects, CNOOC is currently the leading company in the LNG business; it is now expanding business opportunities in other provinces in China.

Several small-size natural gas producers – mainly owned by local governments – are active in China. More recently, small-size inland LNG producers, operated by private companies, are also emerging. In Xinjiang, for example, a new private company recently built a small LNG plant with production capacity of 0.6 bcm (432 000 tons) per year and delivery of LNG by tanker trucks. Such a flexible business makes sense for inland and rural consumers. With regard to CBM, the government established the China United Coalbed Methane Corporation (CUCBM) in 1996 as the sole state-owned company for developing CBM. In 2007, China opened the CBM business to foreign investors in order to accelerate its development.

¹¹ CNPC, Sinopec and CNOOC are now holding companies after devoting their core business to subsidiaries, the shares of which are listed on stock exchanges. CNPC's main subsidiary is PetroChina. In this report, PetroChina is expressed as "CNPC" for the reader's convenience.

Table 5. Key information on Chinese NOCs (2007)

	CNPC/PetroChina	Sinopec	CNOOC
Government share	90%	77.42%	70.6%
Total assets (USD million)	139 848	96 658	23 657
Income (USD million)	110 154	158 938	11 892
Net profit (USD million USD)	20 477	7 458	4 079
Net profit/income ratio	18.6%	4.7%	34.3%
Oil production (1 000 b/d)	2 298	96 658	23 657
Gas production (mcf/d)	4 458	774	560

Sources: Company annual reports.

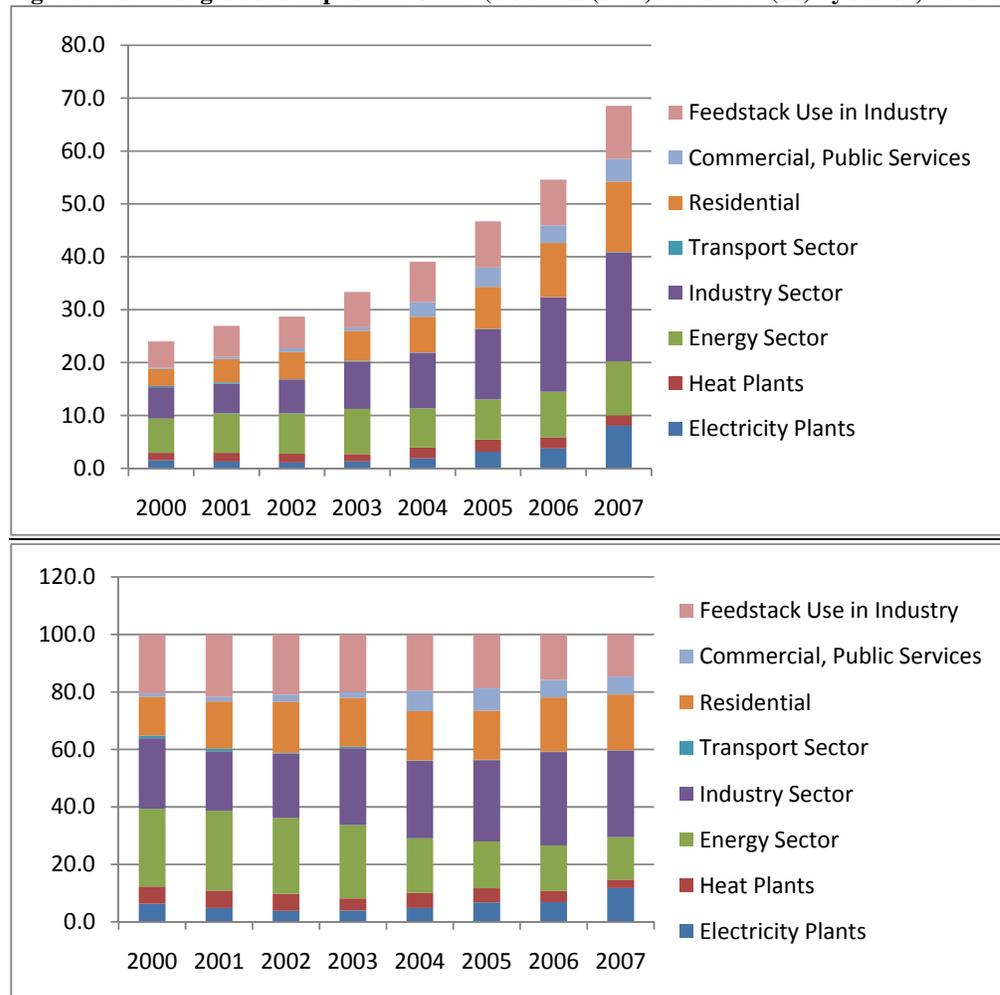
Most distribution companies are owned and managed by local governments, while natural gas is delivered to some major industrial users directly by producers. In 2002, the government opened the city gas business to private and foreign companies, and more than 60 private companies are now distributing in several cities such as Shanghai and Guangdong. LNG receiving terminals are owned and operated by the joint ventures of local government entities, gas users and importing NOCs such as CNOOC and CNPC.

3. Demand and Supply

3.1 Consumption

China's natural gas consumption has been increasing rapidly and attained 69.5 bcm in 2007. According to provisional estimates, in 2008, China's natural gas consumption grew by 11.8% and attained 77.7 bcm. Since 2004, the annual growth rate accelerated to more than 20%, far above the country's GDP growth rate. In the residential sector, increasing city gas penetration, accompanied by rapid city modernisation, pulled up natural gas demand. The development of the pipeline network increased the connectivity to enable the back-up of supply for emerging consuming areas. The government encouraged fuel switching from coal and oil to natural gas in order to reduce air pollution. Moreover, high oil prices forced residential and industrial consumers to shift their fuel and feedstock from oil and LPG to natural gas since the energy equivalent price of natural gas was cheaper than that for oil and LPG at that time. Faced with a steep increase in gas demand, the government issued a new priority sector policy in August 2007, which categorised city residential use and combined systems for heat and power as being top priority (see 2.3 **Policy and regulation**). Since late 2008, the increase in natural gas consumption experienced a slowdown due to falling oil prices and the effect of world economic recession, but maintained steady growth.

Figure 1. Natural gas consumption in China (Volumes (bcm) and share (%) by sector; 2000-07)



Sources: CESY 2008, IEA.

Residential sector

The residential sector¹² is the fastest growing sector in terms of gas demand, and its share in total natural gas consumption increased from 19.0% in 2000 to 25.9% in 2007. Residential gas consumption increased dramatically from 3.7 bcm in 2000 to 17.7 bcm in 2007 – an annual increase of 25%. Until the late 1980s, coal and coal gas were primary fuels even for city residents in the country. Then LPG became used for communal cooking and water heating fuel in several cities. Recently, natural gas use in urban areas has been growing rapidly backed by the development of distribution infrastructure. In order to promote energy efficiency and the reduction of air pollution in cities, the government assisted the replacement of household' fuel change. The IEA estimated the number of Chinese cities with gas distribution at above 140 in 2005 (IEA 2007), a major jump from 60 in 2003; this is expected to rise to 270 in 2010. The number of urban residents with access to gas more than doubled from 32 million in 2001 to 71 million in 2005 – 14% of the urban population. According to the City Gas Association of China, city gas energy consumption (not just for residential use) amounted to 32.3 bcm of coal-gas, 14.7 million tons of LPG, and 30.9 bcm of natural gas, in 2007. This association estimated the number of users to be 40 million for coal-gas, 182 million for LPG and 102 million for natural gas, respectively. Another expert indicated that the penetration ratio of city gas on natural gas bases accounts for 60% in Beijing and 30% in Shanghai. The natural gas use in the residential sector has accelerated since 2005 because the natural gas price remained relatively cheap while the LPG price rapidly increased. At present, the government is placing the top priority of natural gas use in the residential sector, and is planning to increase the number of cities using gas, with a target of 65% urban penetration by mid-century. Natural gas use in transportation is also being promoted. In cities such as Beijing, nearly all public buses now run on compressed natural gas (CNG). In total, China now has about 30 000 CNG-fuel transit buses and 70 000 CNG-fuel taxis.

Table 6. Consumption of city gas by fuel (2003-07)

	2003	2004	2005	2006	2007
Natural gas (bcm)	14.2	16.9	21.1	24.5	30.9
LPG (million ton)	11.3	11.2	12.2	12.6	14.7
Coal gas (bcm)	20.2	21.4	25.6	29.7	32.3

Source: City Gas Association of China (the Statistic Report of Constructing)

Table 7. Comparison of city gas prices (2007)

Fuel	Thermal value	Unit price	Calorimetrical value price
Natural gas	8 300 (kcal/m ³)	2.19 (CNY/m ³)	0.264 (CNY/million cal)
LPG	12 000 (kcal/kg)	2.19 (CNY/kg)	0.490 (CNY/million cal)
Coal gas	3 600 (kcal/m ³)	1.0 (CNY/m ³)	0.278 (CNY/million cal)

Source: CNPC.

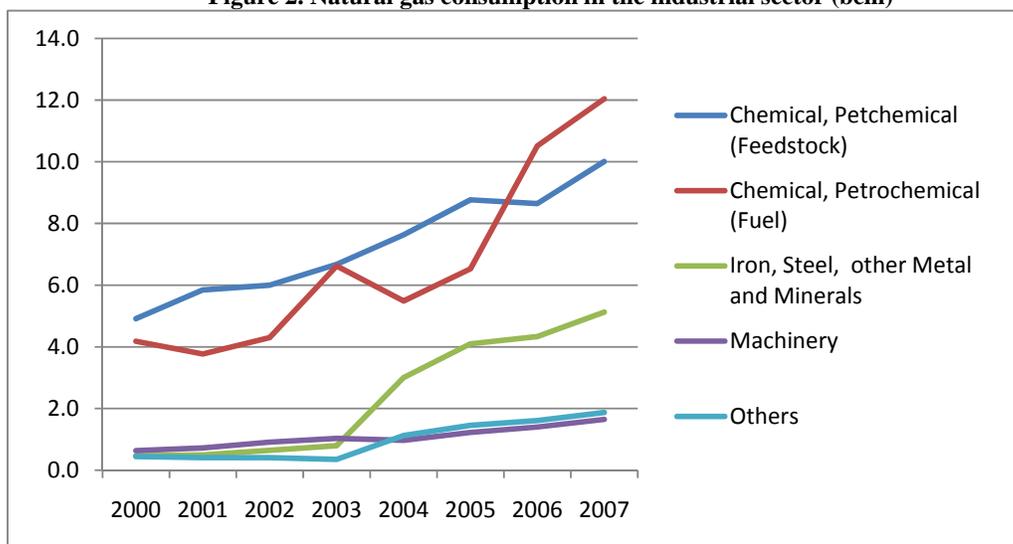
Industrial sector

With the exception of its own consumption in the energy sector, which uses gas mainly for the development of oil and gas fields, the chemicals and petrochemicals industries are major natural gas consumers in China's industrial sector. Natural gas is used as a fuel and feedstock in several industries such as ammonia, methanol and chemical fertilizer production. Fertilizer producers, in particular, have been allocated cheap gas for feedstock because of the industrial and social policy for farmers. Natural gas prices have even been cheaper than increasing oil prices in recent years. As a result, industrial gas consumption increased dramatically from 10.8 bcm in 2000 to 30.6 bcm in 2007, representing a 44.7% share in total consumption in 2007. Confronted by the shortage of natural gas

¹² In this context, "Commercial and Public Service" and "Transportation" as the items on the statistics are combined to the residential sector.

supply and a number of controversial situations, such as overproduction in some chemical and petrochemical plants using cheap gas, the government reviewed its priority policy in 2007, and restricted natural gas use in industry (see 2.3 **Policy and regulation**).

Figure 2. Natural gas consumption in the industrial sector (bcm)



Sources: CESY 2008, IEA.

Power Sector

Although natural gas consumption in the power sector is steadily increasing, it represented only an 11.6% share in total gas consumption in 2007. The government has been promoting the use of natural gas in the power sector from the viewpoint of energy efficiency and environmental benefits. Many gas-fired and combined-cycle power plants were built, particularly in the Shanghai and Guangdong areas. By the end of 2006, the total capacity of gas-fired power plants attained 15.6 GW, or 2.5% of total power generating capacity in China. At the time of planning the West-East Pipeline, power companies in Shanghai were reluctant to use natural gas due to higher prices compared with coal. But their needs substantially increased since electricity demand grew more rapidly than anticipated. In the Guangdong area, a dozen power plants had been waiting for natural gas supply from the Guangdong Dapeng LNG receiving terminal, but they faced both a supply shortage and high prices – in particular LNG spot prices. Shortly afterwards, many gas-fired plants became idle. Indeed, in 2007, it was estimated that the average annual generating hours of China’s gas-fired power plants amounted to 3 500, while those of coal-fired plants amounted to 5 500.

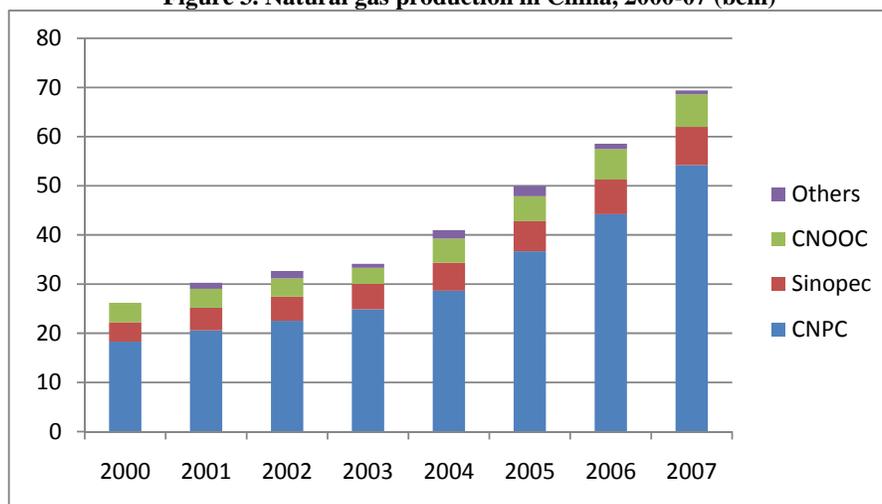
According to the government’s long-term electricity development plan, gas-fired power capacity is expected to reach 70 GW by 2020 (a more recent plan shows capacity of 36 GW by 2010). However, the lesser competitiveness of natural gas prices compared to coal has aroused uncertainties about that plan. Until now, the government has implemented a number of reforms regarding coal prices, including a regulation for the desulfurization of coal-fired power plants, with restricted sulfur emissions. Electricity price reform also took place in several formations, such as the adoption of peak and off-peak pricing systems and the linkage of electricity prices to coal prices. This measure allows for an adjustment of the electricity price if the coal price rises by more than 5% during a six-month period, transferring 70% of the cost change to the consumer. However, those adjustments have not sufficiently changed the competitiveness of natural gas so far. In 2009, following the drop in oil prices, international gas prices also began to decrease but were still more expensive than coal prices in China. Moreover, it seems to be difficult to increase electricity prices given the current economic recession. The relative price issue between coal, natural gas and electricity remains a key challenge for the expansion of natural gas use in China’s power sector.

3.2 Production

China's natural gas production grew at an annual average growth rate of 15% from 2000 to 2007, amounting to 69.2 bcm in 2007. It is estimated to reach 76.1 bcm in 2008. The major producing gas fields are located in the Sichuan Basin (output of 17 bcm in 2007), the Ordos Basin (15.5 bcm) and the Tarim Basin (12 bcm). According to CNPC, as a result of the rapid increase in production in recent years, the reserve/production ratio declined from 51 in 2002 to 47 in 2007 despite the increase in the discovery of reserves. CNPC, the dominant producer, retains a share of about 75% in domestic natural gas production and is accelerating the development of major gas fields with the aim of increasing production. However, CNPC has found that developing upstream gas resources has become increasingly difficult and complex due to the substantial depth of these basins as well as their high pressure, loose sandstone, volcanic pools and high sulfur content. Thus, innovative technologies will be required and development costs will rise subsequently.

With regard to the damage caused by the major earthquake in Sichuan last year, the media reported that 71 oil and gas pipelines, 47 oil tanks and 908 gas stations had been damaged, but not seriously. Almost all of these facilities were operational within one month.

Figure 3. Natural gas production in China, 2000-07 (bcm)



Source: CNPC.

Coalbed methane

Coalbed methane (CBM) has already been produced commercially, mainly in Shanxi province, but in small quantities, amounting to only 0.38 bcm in 2007 despite the abundance of resources. In the 11th Five-Year Plan (2006-2010), the government planned to promote the development of CBM as a supplementary source of natural gas, targeting 10 bcm by 2010. In 2007, the government opened the CBM business to foreign investors and adopted a tax incentive policy. In late 2007, China succeeded in obtaining UN-certified carbon credits in the placement of CBM-fired power plants. CBM development is relatively effective for reducing greenhouse gas (GHG) emissions because the methane release from coal mines is more potent as a greenhouse gas than carbon dioxide (CO₂). Thus, CBM development in China is now attracting international attention due to CDM¹³ business opportunities.

¹³ Clean Development Mechanism under the Kyoto Protocol.

3.3 Import

Liquefied natural gas (LNG)

In the late 1990s, China started planning LNG imports in order to meet the strong gas demand coming from coastal cities. Guangdong, one of the most important emerging economic centres and often known as “the factory of the world”, was chosen as the site for the country’s first LNG regasification terminal. CNOOC, a Chinese pioneer of LNG, negotiated with several suppliers and finally signed a long-term sales and purchase agreement (SPA) with the seller of the Australian NWS project in 2003. CNOOC is said to have obtained quite an advantageous LNG price based on the JCC¹⁴-linked price formula thanks to the situation of a “buyers’ market” at that time. This price formula is said to have a flat ceiling not exceeding USD 3.16 per MBtu even with oil prices above USD 30 b/d. In June 2006, the first cargo arrived at the Guangdong Dapeng LNG terminal from Australia. By the end of 2008, this terminal had received a total of 3.7 bcm (2.7 million tons) of long-term contract-based LNG, and in addition, 0.8 bcm (618 000 tons) of spot LNG. Backed by the strong demand for gas in this area, CNOOC bought spot cargoes from Oman, Algeria, Nigeria, Egypt, Ecuador and Equatorial Guinea despite high prices (USD 8.2 to USD 20.6 per MBtu). The construction of the second LNG terminal in Fujian has been completed, and the first cargo from Indonesia’s Tangguh project is expected to be delivered in 2009. The third terminal in Shanghai will open in mid-2009,¹⁵ with LNG supplies coming from Malaysia’s Tiga project. CNOOC signed a SPA with Indonesian and Malaysian sellers, in which the LNG price formulae are said to be less advantageous than that of NWS, without any ceiling or “S-curve”,¹⁶ due to the shifting situation from a buyers’ market to a sellers’ market.

Following these three projects initiated by CNOOC, CNPC is promoting the delivery of LNG in Dalian and Jiangsu, where receiving terminals are now under construction and expected to be operational by 2011. As far as the LNG supply source is concerned, CNPC initially planned to import primary from Gorgon or Browse LNG projects in Australia. However, the completion schedule of these projects has been delayed, and CNPC signed a SPA with the seller of the QatarGas IV project in 2008. It is said that CNPC accepted a less favorable price formula because Qatar proposed an oil-parity price formula to world buyers at that time, backed by a strongly boosted LNG market. If this is true, then the angle of incline in the formula would be nearly 16 degrees, which means that the LNG price would be USD 16 per MBtu for an oil price of USD 100 per barrel. In November 2008, CNPC signed another SPA of 2.7 bcm (2 mtpa) with Shell; the LNG may be supplied by Australia’s Gorgon project and supplemented by additional LNG volumes from Shell’s portfolio.

CNOOC signed two SPAs in 2008, one with the QatarGas II project and another with Total, probably intending to meet the increase in demand by the expansion of the Guangdong terminal and the start of the new terminal in Zhejiang. Most recently (March 2009), CNPC signed a SPA of 2.7 bcm (2 mtpa) from ExxonMobil’s portion of the Gorgon production. In May 2009, CNOOC signed a project development agreement with BG Group regarding the Queensland Curtis LNG project in Australia, which will provide 5 bcm (3.6 mtpa) of LNG to China. As a result of these procurements of LNG by CNOOC and CNPC, the total contracted volume on a long-term basis has now accumulated to attain 30.6 bcm (22.5 mtpa).¹⁷

¹⁴ Japan Crude Cocktail (the average import price of crude oil in Japan)

¹⁵ Some media reported the first cargo was delivered in 2008, but that was a shipment to another small plant in Shanghai.

¹⁶ In the LNG price formulae link to oil prices, the conversion ratio from oil value to LNG can be illustrated as the angle of the slope. The traditional LNG formulae show the shape of an “S-curve”: the angle changes to slightly when the oil price rises above or drops below a certain level (similar to the ceiling and floor price).

¹⁷ Other non-confirmed agreements have been reported such as: a non-binding agreement between CNPC and Woodside (Browse, 2.0 mtpa to 3.0 mtpa); a head of agreement (HOA) between CNPC and Iran (South Pars, 2.0 mtpa); a memorandum of understanding (MOU) between Sinopec and Iran (South Pars, 10 mtpa); an HOA between Hong Kong CLP and BG (1.0 mtpa); and an HOA between CNOOC and Interoil (PNG). Some Chinese media recently reported that Macau has signed an MOU with Indonesia for 2.0 mtpa to 5.0 mtpa.

Since 2006, the international LNG market has become tight, with sellers moving to increase LNG prices in long-term contracts close to oil parity. Moreover, spot LNG prices rose sharply, particularly in 2007, due to a few extraordinary factors such as increasing demand in Japan caused by the outage of nuclear plants. Given this background, new LNG terminal projects were suspended in China despite increasing demand in several coastal cities because it was difficult to obtain new LNG supplies at acceptable prices. The recent global financial crisis and economic recession have caused yet another change in the international gas market – back to a buyers` market. Gas prices are falling sharply, on either a spot or long-term contract basis, following the drop in oil prices. Consequently, several terminal projects now seem to be starting up again in China.

Table 8. Existing long-term LNG sales and purchase agreements (SPAs)

Buyer	Supply source	Volume (mtpa)	Term (years)	Signing date	Destination terminal (Capacity - mtpa)	First cargo
CNOOC	Australia NWS	3.3	25	2003 Dec	Guangdong (3.7)	2006 Jun
	Indonesia Tangguh	2.6	25	2006 Sep	Fujian (2.6)	2009 May
	Malaysia Tiga	3.0	25	2006 Jul	Shanghai (3.0)	2009
	QatarGas II	2.0	25	2008 Jun	Multi-destination?	2009
	Total (Portfolio)	1.0	15	2009 Jan	Multi-destination?	2010
	Australia QC LNG	3.6	20	2009 May		2014
CNPC	QatarGas IV	3.0	25	2008 Apr	Jiangsu? (3.0)	2011
	Shell (Gorgon+)	2.0	20	2008 Nov	Dalian? (3.5)	2011
	ExxonMobil (Gorgon)	2.0	20	2009 March		2014
Total		22.5				

Source: Media reports

Pipeline gas

Since the early 1990s, China has held many discussions with Russia on several pipeline projects, with the aim of importing natural gas from Russian gas fields such as Kovyktinsoye in Irkutsk, West Siberian (through the planned Altai Pipeline), Sakha in East Siberia, and Sakhalin. To date, no real progress has been observed on any of these projects. This prompted China to change its strategy, focusing instead on Central Asia, and led to the successful conclusion of a major deal for natural gas supply from Turkmenistan. Following an inter-governmental agreement between China and Turkmenistan in April 2006, CNPC and Turkmenistan signed two significant agreements in July 2007: a production sharing contract (PSC) for the Bagtyarlyk gas field in the Amu Darya River Right Bank; and a 30-year SPA of 30 bcm of natural gas with Turkmenistan. In August 2008, both parties agreed to increase the sales volumes on the SPA to 40 bcm as offered by the Turkmen President Berdymukhammedov on the occasion of his visit to the Beijing Olympics.

In order to transport Turkmen gas to the Chinese border via Uzbekistan and Kazakhstan, China planned the Central Asia-China Pipeline, and rapidly obtained confirmation from these two transit countries about co-operation for the pipeline. This cross-border pipeline, which has a total length of 2 006 km and a capacity of 30 bcm, is now under construction. The first pipeline for 10 bcm is expected to be completed and connected to the second West-East Pipeline by the end of 2009; the remaining capacity of 20 bcm is planned to be completed by 2015. The total cost is estimated to be USD 7.3 billion, which may be financed by China. To build and operate the pipeline in each of the

two transit countries, CNPC established two joint venture companies: one with Uzbekneftegaz and one with Kazmunaigaz.

Although the detailed contents of the agreement have not been disclosed, CNPC indicates that a portion of the agreed gas will be sourced from the Bagtyiarlyk gas field which CNPC is developing based on the PSC. This field is expected to produce up to 13 bcm per year. The remaining 30 bcm (initial agreed volumes) will be provided based on the SPA. It is not clear whether the remaining portion, initially 17 bcm to be increased to 27 bcm, is guaranteed to be supplied from other gas fields. Whatever the case, possible import gas volumes from Turkmenistan to China are highly dependent on future production, and ultimately, on the quantity of recoverable reserves in Turkmenistan. In June 2009, media reported that China has agreed to extend USD 3 billion loan to Turkmenistan to develop the South Yolotan gas field, which is estimated to contain between 4 tcm and 14 tcm. Although details of the agreement have not been disclosed, this deal may ensure the gas supply from Turkmenistan to China. With regard to the gas price (which is naturally a most confidential matter), both parties have reported that the price will be based on “international market prices”, a rather opaque formulation.

CNPC is also actively exploring Aktyubinsk and Urikhtau in Kazakhstan, and the Aral Sea in Uzbekistan. In November 2008, CNPC and Kazmunaigaz signed a comprehensive agreement for co-operation on natural gas development, including the construction of another gas pipeline from Aktyubinsk to be connected to the Central Asia-China Pipeline. At present, the potential of Kazakhstan`s gas exports is not expected to exceed 10 bcm.

Additional pipeline gas imports are being planned from Myanmar to the southern part of China. In December 2008, China and Myanmar signed an SPA for 10 bcm of natural gas with a planned 1 000 km pipeline. This project also appears to be advancing, with announcements in June 2009.

Turkmen Gas

1. Reserves

Turkmenistan, an inland country with a small population of 6.7 million, has been attracting significant attention recently on the international gas market because of its huge potential in terms of gas reserves and exports. In 2007, total gas resources were estimated to be more than 20 tcm (IEA 2008 b). In 2008, an international audit identified the Osman/South Yolotan field as being a super giant gas field. The best estimate of gas-initially-in-place at the vast Osman/South Yolotan field (now considered a single structure) was 6 tcm of gas, within a range of 4 tcm to as high as 14 tcm. In 2009, BP reported proven reserves of around 7.94 tcm, ranking Turkmenistan as the fourth-largest gas holder in the world following Russia, Iran and Qatar.

Despite abundant potential, natural gas production and exports have been restricted in Turkmenistan due to the lack of trans-border pipelines (except to Russia and Iran). In 2007, Turkmenistan's production of natural gas was 72 bcm, while domestic consumption was less than 20 bcm. Almost all the rest, around 50 bcm, is exported to Russia, based on long-term contracts, and subsequently sold to Ukraine (where natural gas consumption was 58 bcm in 2007). Exports to Iran amounted to 0.8 bcm in 2007, but stopped in 2008 due to the dispute over gas prices.

The Turkmen government intends to raise natural gas production to 250 bcm by 2030, but this plan faces several uncertainties. In principle, the government has not opened the onshore upstream sector to foreign companies. In 2007, CNPC became the first exception to obtain a production sharing contract (PSC) for onshore gas field development in Turkmenistan. It is said that China's package offer – which included a favourable price, stable off-take and entire responsibility for pipeline construction (together with financing) – was highly acceptable for Turkmenistan. Foreign investments in the Caspian offshore are encouraged by the open-door policy of President Berdymukhammedov but progress on new projects has been slow.

2. Prices

The export price of Turkmen gas to Russia is closely affecting Russia-Ukraine sales prices and, indirectly, Russia-Europe sales prices. As is true of gas prices from other CIS countries to Russia, Turkmen gas export prices were relatively cheap until recently. Since 2005, Russia and three Central Asian countries – Kazakhstan, Uzbekistan and Turkmenistan – discussed and concluded (March 2008) that gas export prices should be determined based on the "European Net-back Price". In September 2006, the Turkmen-Russian gas price was increased from USD 60 per 1 000 m³ to USD 100 per 1 000 m³. In April of the same year, the Chinese and Turkmen governments signed a comprehensive agreement on natural gas development and exports. In the meantime, Russia increased gas prices to Ukraine from USD 50 per 1 000 m³ to USD 95 per 1 000 m³ in 2006, and then to USD 130 per 1 000 m³ in 2007. Due to the increase in European gas border prices, Turkmenistan insisted that the export gas price in 2008 should be USD 190 per 1 000 m³. Russia settled the gas sales price to Ukraine at USD 179.5 per 1 000 m³ in 2008, and the import price from Turkmenistan at USD 130 per 1 000 m³ in the first half of 2008, increasing to USD 150 per 1 000 m³ during the latter part of the year.

In July 2007, CNPC and Turkmenistan signed a PSC and a SPA. In January 2008, media reported that both parties had agreed on a gas price of USD 195 per 1 000 m³, based on an oil linkage. Although it is not clear what this agreed price indicates, several news sources have suggested that it may not be the actual delivery price but the indicated price as reflected by the market price at the time of the agreement. One of interpretative points is whether this agreed price is the price at the Turkmenistan border or at the Chinese border. If it is the

Chinese border price, the assumed export price at Turkmenistan would be around USD 145 per 1 000 m³ because the pipeline tariff for transit countries (Uzbekistan and Kazakhstan) is estimated around USD 50 per 1 000 m³ (USD 195 - USD 50 = USD 145 per 1 000 m³). This price level was slightly higher than Russia-Turkmen export price at that time (USD 130 per 1 000 m³), but may not have satisfied Turkmenistan as the government insisted on increasing export prices drastically.

Another interpretation is that the agreed price of USD 195 per 1 000 m³ would indicate the Chinese border price. In this case, the Chinese border price would be USD 245 per 1 000 m³ (USD 195 + USD 50). If it is true, this price level may completely satisfy Turkmenistan while Russia may feel pressured to increase its import price from Turkmenistan.

In 2008, the international natural gas price increased following the oil price. A CNPC expert mentioned in a conference in September 2008 that under that market situation, the Turkmen border price could be around USD 230 per 1 000 m³ (USD 6.1 per MBtu) resulting in more than CNY 2 per m³ (USD 288 per 1 000 m³, USD 7.6 per MBtu) at the Chinese border, and CNY 3 per m³ (USD 432 per 1 000 m³, USD 11.4 per MBtu) at the Shanghai city gate. In this case, the city gate price in Shanghai would be at almost the same price level as that of the European market, but almost double the existing price in Shanghai.

In August 2008, it was reported that Russia and Turkmenistan had agreed upon a new gas price formula (adopted since 2009), setting the import price as a mix of sale prices in Europe and Ukraine, in equal proportions, for the six previous months. As those prices amounted to around USD 400 per 1 000 m³ and USD 200 per 1 000 m³ in 2008, respectively, the Turkmen gas price could be USD 300 in 2009. According to another announcement, the price in Southern Russia of USD 70 per 1 000 m³ at that time will be taken into the calculation. In this case, Turkmen gas will amount to USD 223 per 1 000 m³. In January 2009, after their major gas dispute, Russia and Ukraine settled the gas price in 2009 as a 20% discount from the European Net-back Price, *i.e.* USD 360 per 1 000 m³ for the first quarter of 2009, to be renewed quarterly. Gas experts predict that it will drop to around USD 250 per 1 000 m³ in late 2009.

Table 9. Chronology of Turkmen gas price negotiation (USD per 1 000 m³)*†

	Europe	Russia-Ukraine	Turkmen-Russia	Turkmen-China		
				Turkmen Border	Chinese Border	Shanghai City Gate
2006 Jan-Sep		95.0	60			
2006 Sep-Dec		95.0	100			
2007	270-290	130.0	100			
2008 Jan-Jun	350-400	179.5	130	<i>195</i>	<i>245</i>	<i>389</i>
2008 Jul-Dec	400-450	179.5	150	<i>230</i>	<i>280</i>	<i>424</i>
Early 2009	350-400	360.0	<i>223-300</i>			

Italic figures indicate author's simulation based on media reports.

* Pipeline tariff for Kazakh and Uzbek is assumed as USD 50 per 1 000 m³.

† Pipeline tariff for the second West-East Pipeline is assumed as USD 144 per 1 000 m³.

3. Pipeline tariffs

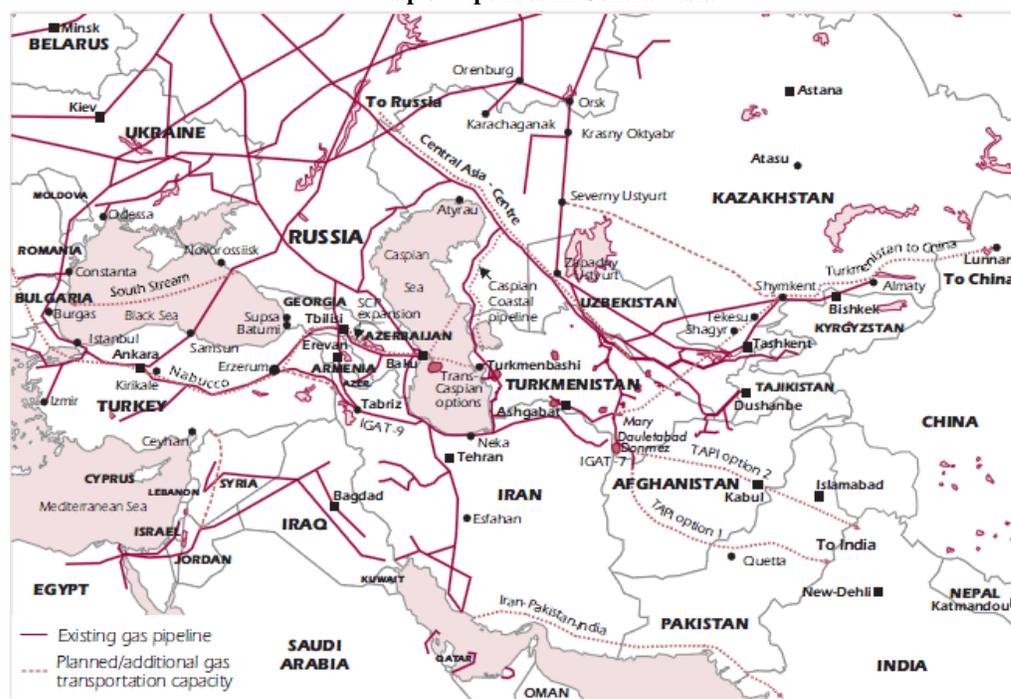
Pipeline tariffs from Turkmenistan to Ukraine have not been disclosed, but the total amount of USD 30 to USD 40 per 1 000 m³ may be paid for pipelines with a total length of 2 300 km (Uzbekistan - 200 km; Kazakhstan - 820 km; Russia - 1 100 km), *i.e.* the unit tariff per 100 km is calculated in the range of USD 1.3 to USD 1.7 per 1 000 m³. The Central Asia-China Pipeline is planned to run through 188 km in Turkmenistan and 1 818 km through two transit countries (525 km in Uzbekistan; 1 293 km in Kazakhstan). The pipeline tariff for the two transit countries is reported as USD 50 per 1 000 m³.^{*} In this case, the unit tariff is USD 2.75 per 1 000 m³, which is almost the same level as the current unit tariff of the first West-East Pipeline for Shanghai users (USD 2.9 per 1 000 m³ for the industrial sector). It is almost double the current tariff for the existing pipeline from Turkmenistan to Ukraine, but seems to be a reasonable level for the newly built pipeline.

^{*} Assuming a total capital cost of USD 7.3 billion financed by a 25-year loan with an interest rate (or IRR) of 12%, the tariffs are calculated to USD 31 per 1 000 m³. The remaining portion of USD 50 per 1 000 m³ includes operational costs and other expenses.

Table 10. Tariffs of the Central Asia Pipeline (simulation)

Total capital cost	USD 7.3 billion
Total length	1 818 km
Gas volume	30 bcm per year
Assumption: annual interest rate	12%
Assumption: repayment terms	25 years
Repayment amount per year (R)	USD 930 million
Tariff/1 000 m ³ = R/30 bcm*1 000 (T)	USD 31/1 000 m ³
Unit tariff/100 km = T/1 818 km/100	USD 1.7/1 000 m ³

Map 3. Pipelines in Central Asia



Only major trunk lines (mostly trans-national) are shown.

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

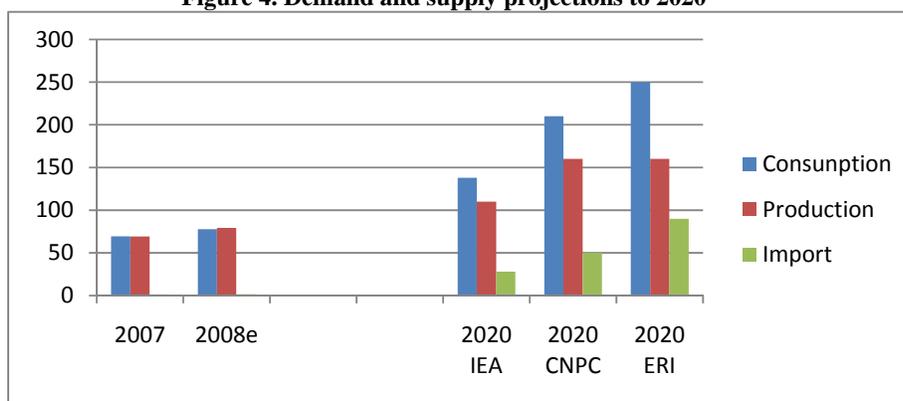
3.4 Future demand and supply projections

The global financial crisis and the economic recession are affecting the Chinese economy. China's monthly export amount has been decreasing since November 2008 in comparison to that of the previous year, and recorded the largest fall of 25.7% in February 2009. The decrease in exports particularly hit the economy in coastal areas, since many export-oriented industries are located there. In January 2009, the government issued a large-scale two-year "stimulus plan" amounting to CNY 4 trillion (USD 580 billion) in order to stimulate the economy and to maintain an annual GDP growth rate of above 8%. Although the precise measures of this plan are still not clear, public investment in infrastructure may be a pillar to expand domestic demand in the country.

As far as China's future demand of natural gas is concerned, consumption in the residential sector deems to keep growth backed by the continuous priority policy for energy diversification and by increasing public investment for related infrastructure while the industrial use of natural gas will decline. ERI is now reviewing its long-term demand projection for natural gas, which was published in 2005, as being 250 bcm by 2020. The IEA showed a relatively conservative projection in its Reference Scenario of *WEO 2008* that China's natural gas consumption will attain 138 bcm by 2020 while domestic production will amount to 110 bcm. According to CNPC's projection of natural gas (as shown in late 2008), consumption will amount to 210 bcm in 2020 with the major consumers being the residential sector (30 bcm), the chemicals industry (44 bcm) and the power sector (54 bcm). Regarding domestic production, CNPC showed an aggressive perspective that China can maintain the high pace of increase in natural gas production despite geological difficulties, attaining 160 bcm to 170 bcm by 2020.¹⁸ Thus, it seems reasonable at the present time to assume that consumption will lie in the range of 180 bcm to 200 bcm, and production in the range of 120 bcm to 140 bcm by 2020. Based on this assumption, the gap between demand and domestic production by 2020 will amount to between 40 bcm and 80 bcm.

As mentioned in the previous section, China has already procured a total of 30.6 bcm (22.5 mtpa) of LNG supply based on long-term contracts and over 30 bcm of pipeline gas from Turkmenistan. This suggests that China is confident about the quantity of natural gas supply, and has sufficient time to negotiate additional imports of natural gas with supply countries.

Figure 4. Demand and supply projections to 2020



Source: IEA, CNPC, ERI

¹⁸ In early 2009, the Ministry of Land and Resources announced a more aggressive projection that China's natural gas production will attain 160 bcm by 2015.

4. Gas Prices

4.1 Current price regime

Like other energy prices, natural gas prices have been under government control in China. In the case of oil and oil products, expanding imports have pushed domestic prices closer to international market prices since China became a net oil importer in 1993. In 2007, faced with increased demand and increasing imports, the government ceased price controls for coal and began reforms towards a market mechanism base. To promote the use of natural gas use, the government has maintained a “cost-plus” based price regime. This has resulted in relatively cheap prices compared to international markets – particularly as a substitute for coal. The gas price regime was sustainable until recently (*i.e.* until LNG imports began in 2006) because China was self-sufficient in natural gas. However, this regime is now being challenged by the projected significant increase in gas imports.

China’s current price regime for domestic natural gas comprises three elements: (A) ex-plant price; (B) transportation tariff; and (C) end-user price (Wu 2008). Both (A) and (B) are under the control of the central government, while (C) is under the control of the local government of each province. (A) is determined principally on the production cost of natural gas (wellhead cost plus purification fee, including financing cost and tax) plus the appropriate margin for producers (IRR 12%). (B) is determined based on the pipeline cost (construction and operation) plus the appropriate margin (IRR 12%) with the variation of transport distance from each gas source to each city gate. The city gate price is (A) + (B). These are fixed prices and can be reviewed as being within 8% of former prices, but not regularly (in fact, the price increase has been implemented on an *ad hoc* basis and sometimes more than 8%). Each provincial government determines (C) by taking into account the distribution cost, alternative fuel prices and other market policy factors. With regard to gas imports (at present, only LNG to Guangdong), end-user prices are remote from government control and are determined according to import prices.

A) Ex-plant price

The central government decides the ex-plant price of each gas field,¹⁹ and sets different prices by end-user – *e.g.* fertilizer, industrial, residential and power sectors. Sellers (producers) and buyers have a free hand in negotiating and setting the actual prices within the 10% allowance from the baseline decided by the government. Ex-plant prices were relatively cheap until the late 1990s because associated gas was dominant in production, and natural gas use was limited. Since early 2000, ex-plant prices have increased in several phases. In November 2007, the government decided to drastically increase ex-plant prices. For the industrial sector, the average price rose by 50% from around CNY 800 per 1 000 m³ (USD 3.04 per MBtu)²⁰ to CNY 1 200 per 1 000m³ (USD 4.57 per MBtu). However, China’s ex-plant prices were still far cheaper than the international prices for natural gas, which peaked at around USD 13 per MBtu in 2008.

¹⁹ Ex-plant prices of natural gas transported by major inter-province pipelines are not determined by gas fields, but by each pipeline base – reflecting the fact that multiple gas fields are connected to these pipelines.

²⁰ Exchange rate: Chinese yuan (CNY) = USD 0.14404 (the average rate in 2008).

Table 11. Ex-plant prices by gas field and by sector (2008)

Gas field	Sector	Ex-plant	Ex-plant
		CNY/1 000 m ³	USD/MBtu
Chunyu	Fertilizer	690	2.62
	Industry	1 275	4.84
	Residential	920	3.50
Changqing	Fertilizer	710	2.70
	Industry	1 125	4.27
	Residential	770	2.93
Qinghai	Fertilizer	660	2.51
	Industry	1 060	4.03
	Residential	660	2.51
Xinjiang	Fertilizer	560	2.13
	Industry	985	3.74
	Residential	560	2.13
Dagang Liaohe Zhonghuan (category 1)	Fertilizer	660	2.51
	Industry	1 320	5.02
	Residential	830	3.15
Dagang Liaohe Zhonghuan (category 2)	Fertilizer	980	3.72
	Industry	1 380	5.24
	Residential	980	3.72

Source: CNPC.

B) Transportation tariff

The transportation tariff is principally determined by distance. In the case of 500 km, the tariff is CNY 85 per 1 000 m³ (USD 0.32 per MBtu), which means that the unit tariff per 100 km is USD 2.24 per 1 000 m³. Current tariffs are fixed for each pipeline, thus reflecting the construction cost. Regarding the Ordos-Beijing Pipeline, for instance, the tariffs are CNY 310 per 1 000 m³ (USD 1.18 per MBtu) for Shanxi Province and CNY 480 per 1 000 m³ (USD 1.82 per MBtu) for Tianjin. The tariffs of the West-East Pipeline are CNY 680 per 1 000 m³ (USD 2.58 per MBtu) for Henan Province and CNY 800 per 1 000 m³ (USD 3.04 per MBtu) for residential sectors in Shanghai. Since the total length of the pipeline from Xinjiang to Shanghai is approximately 3 900 km, the unit tariff per 100 km is calculated to be USD 2.9 per 1 000 m³ in Shanghai.

Table 12. Transportation tariff by distance (2008)

Distance (km)	Tariff		
	(CNY/1 000 m ³)	(USD/1 000 m ³)	(USD/MBtu)
<50	36	5.19	0.14
50-100	41	5.91	0.16
101-200	47	6.77	0.18
201-250	58	8.35	0.22
251-300	63	9.07	0.24
301-350	68	9.79	0.26
351-400	74	10.66	0.28
401-450	79	11.38	0.30
451-500	85	12.24	0.32

Source: CNPC

Table 13. Ordos-Beijing Pipeline Gas (2008)

Destination	CNY/1 000m ³			USD/MBtu
	Ex-plant	Pipeline tariff	City gate	City gate
Shaanxi	830	120	950	3.61
Shanxi	830	310	1140	4.33
Shandong	830	400	1230	4.67
hebei	830	420	1250	4.75
Beijing	830	450	1280	4.86
Tianjin	830	480	1310	4.55

Source: CNPC

Table 14. West-East Pipeline Gas (2008)

Destination	Sector	CNY/1 000 m ³			USD/MBtu
		Ex-plant	Pipeline tariff	City gate	City gate
Henan	Industry	960	640	1 600	6.08
	Residential	560	680	1 240	4.71
Anhui	Industry	960	750	1 710	6.50
	Residential	560	750	1 310	4.98
Jiangsu	Industry	960	790	1 750	6.65
	Residential	560	940	1 500	5.70
	Power	560	620	1 180	4.48
Zhejiang	Industry	960	980	1 940	7.37
	Residential	560	980	1 540	5.85
	Power	560	720	1 280	4.86
Shanghai	Industry	960	800	1 760	6.69
	Residential	560	980	1 540	5.85
	Power	560	670	1 230	4.67

Source: CNPC.

C) End-user price

Various city gate prices are determined according to a matrix of the ex-plant prices of each gas field for each sector and transportation tariffs of each pipeline for each city. Based on these city gate prices, each local government fixes end-user prices or the sales prices of local distribution companies, again using the sector variation. At the end of 2007, many provincial governments decided to drastically increase end-user prices, particularly in the industrial sector, responding to the central government's decision to increase ex-plant prices and the restrictive policy of the industrial sector. At that time, natural gas demand was bullish faced with high prices of oil and LPG. Because of the distance between major gas fields and coastal cities, end-user prices in these cities are relatively high. However, end-users are better able to afford higher prices thanks to a stronger economy. Consequently, China's end-user prices show a "ladder structure of low-high from west to east". In Shanghai, for example, the price for industrial users was increased by 16% to CNY 2 900 per 1 000 m³ (USD 11.02 per MBtu) whereas those at Lanzhou (Gansu Province) remained at CNY 1 250 per 1 000 m³ (USD 4.75 per MBtu).

Table 15. End-user prices for public service and industrial use in major cities (2008)*

Province	City	CNY/1 000 m ³				USD/MBtu	
		Public service		Industry		Public service	Industry
Beijing		2.55		2.35	21%	9.69	8.93
Tianjin		2.40		2.40		9.12	9.12
Hebei	Shijiazhuang	2.40		2.00		9.12	7.60
Neimenggu	Hohhot	1.92		1.67	31%	7.30	6.35
Liaoning	Shenyang	3.60		3.00		13.68	11.40
Jilin	Changchun	1.80		1.80		6.84	6.84
Heilongjiang	Harbin	3.00		2.50		11.40	9.50
Shanghai		3.30		2.90	16%	12.54	11.02
Jiangsu	Nanjing	3.00		2.75	20%	11.40	10.45
Zhejiang	Hangzhou	2.40		2.35		9.12	8.93
Zhejiang	Ningbo	3.40		3.40		12.92	12.92
Anhui	Hefei	2.10		2.48	21%	7.98	9.42
Shandong	Jinan	3.29	17%	3.29	17%	12.50	12.50
Shandong	Qingdao	3.60		3.60	25%	13.68	13.68
Henan	Zhengzhou	2.40		2.50	19%	9.12	9.50
Hubei	Wuhan	3.28		2.63	20%	12.46	9.99
Hunan	Changsha	2.55		2.28		9.69	8.66
Guangxi	Nanning	4.19		4.19		15.92	15.92
Hainan	Haikou	3.73	20%	3.30	40%	14.17	12.54
Chongqing		2.21		1.67	35%	8.40	6.35
Sichuan	Chengdu	1.72		1.66	35%	6.54	6.31
Shaanxi	Xi'an	1.75		1.75		6.65	6.65
Gansu	Lanzhou	1.88		1.25		7.14	4.75
Qinghai	Xining	1.70		1.47	37%	6.46	5.59
Ningxia	Yinchuan	1.98		1.38		7.52	5.24
Xinjiang	Urumqi	1.88		0.00		7.14	0.00

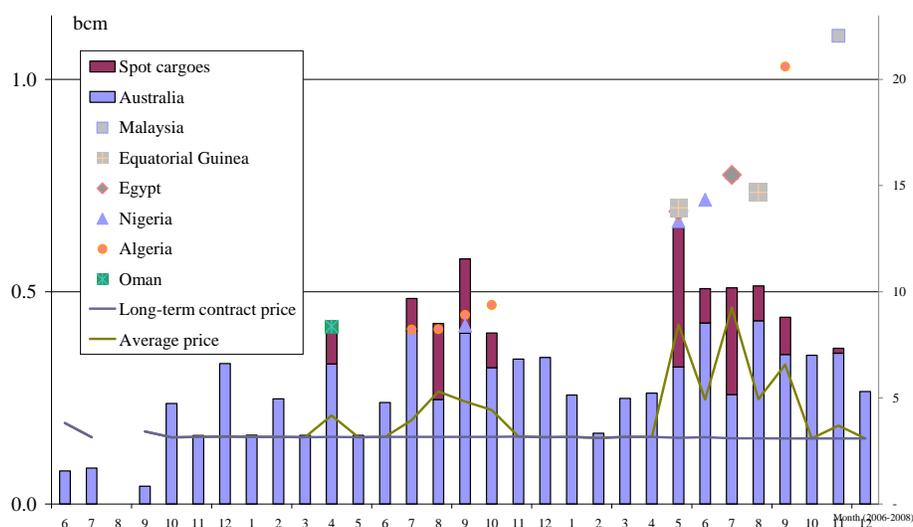
Source: CNPC

*The percentage shows the increase from the previous year (2007).

Import gas price

China currently imports natural gas only at the Guangdong Dapeng LNG terminal. This terminal received LNG of 4 bcm (2.9 million tons) in 2007 and 4.5 bcm (3.3 million tons) in 2008, which were delivered mainly from Australian NWS project, based on a long-term contract. The LNG price in the contract is said not to exceed USD 3.16 per MBtu. Most of the gas is delivered to power companies, for which the sales price is fixed based on the long-term contract's import price, plus regasification and distribution costs. The remainder is primarily distributed to city gas and to Hong Kong. In order to satisfy the strong demand for LNG in these areas, the terminal received several spot cargoes of LNG in 2007-08. Despite bullish prices of spot LNG at that time, high-price LNG was accepted by the residential and industrial sector because it was cheaper than LPG and oil products. By contrast, the power sector was reluctant to use such expensive gas. Thus, the load factor of several gas-fired plants remained at a low level.

Figure 5. Volumes and prices of imported LNG to Guangdong (2006-08)



Source: IEA.

4.2 Recent trends and challenges

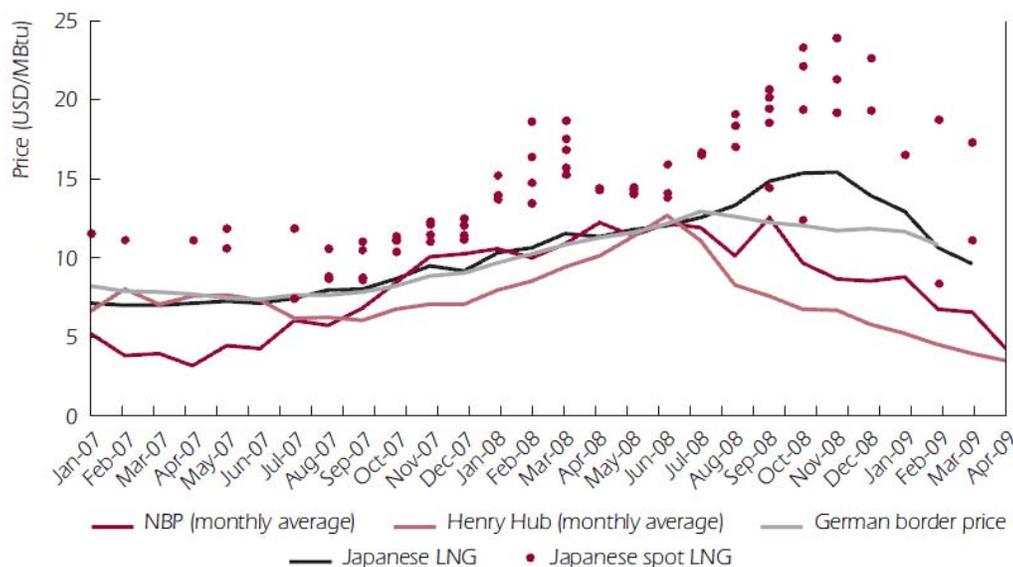
Together with the evolution of the natural gas market in China, the current price regime has is known to have to several structural defects. First of all, additional inflows of natural gas from multiple gas fields to the same pipeline distributing to multiple users are causing difficulties in identifying the gas source and the original cost. In the early stage of market development in China, the gas supply chain was simple. Recent expansion of interconnected networks gives the impression of unfairness and poses a question directly both to producers and users, namely: *Who is using low-cost gas?* Secondly, the sector priority policy for allocation and pricing of natural gas reveals the difficulty of having to adjust to the inter-sector imbalance of demand and supply, as well as to seasonal and regional imbalances. On the user side, fixed and relatively cheap prices fail to provide motivation for peak saving and efficient use of natural gas. On the upstream side, cheap prices do not give incentives for developing more costly gas fields or improving technology.

This inflexible price regime for natural gas has had its limits, particularly in relation to high oil prices in 2007. In the residential sector, the fact that the natural gas price was cheaper than LPG promoted a fuel switch. In the industrial sector, cheap gas prompted the over-production of a number of petrochemical products (*e.g.* methanol and ethanol). In the fertilizer industry, some producers exported products made from cheap gas – products that the government intended to allocate in favour of domestic farmers.

Another serious situation occurred due to the expanding gap between international and domestic gas prices during early 2007 and mid-2008, which occurred for several reasons. Natural gas prices based on long-term contracts were gradually increasing since prices are determined by the price formula link to oil and/or oil product prices with a certain time lag. At the same time, LNG demand was strong across the Asia-Pacific market for the same reasons as in China (*i.e.* increased industrial use backed by relatively cheap gas prices compared to LPG or oil products) and due to emerging demand in Japan caused by nuclear plant outage in 2007. As a result of this boosted demand for LNG, spot cargo prices jumped – sometimes above USD 20 per MBtu. Such a LNG price level in the Asia-Pacific market directly affected the LNG spot price in the Atlantic market and indirectly influenced pipeline hub prices in Europe and the USA. During the same period, CNPC and CNOOC sought new LNG supply sources for their newly built terminals, and negotiated with several sellers. In the “sellers’ market”, LNG sellers were eager to increase LNG prices close to “oil parity”, *i.e.* the degree of incline in the

price formula in long-term contracts was to be 17.5 degrees. This means the LNG price would be USD 17.5 per MBtu for an oil price of USD 100 per barrel, more than three times the city gate price in China at that time.

Figure 6. International prices of natural gas (2007-09)



Sources: IEA, *Natural Gas Market Review 2009* (IEA 2009).

At the same time, China was negotiating the price of imported pipeline gas with Turkmenistan. As mentioned in the previous section, the price of Turkmen gas at the Chinese border is thought to be around USD 245 per 1 000 m³ (USD 6.5/MBtu). This price may indicate the price level at the timing of the agreements in January 2008, and is probably changeable, based on some price formula link to oil. Fortunately for China, the international gas price has been falling since late 2008. Nonetheless, the price level of Turkmen gas could still be expensive for users in eastern coastal cities in China, which have to pay transportation tariffs for the long distance of the second West-East Pipeline. The impact of importing gas from Turkmenistan on China's current price regime could be more significant and extensive than that of LNG because its volume will attain 30 bcm to 40 bcm per year, whereas the total volume of newly contracted and high-price LNG is 18.5 bcm (13.6 mtpa). Furthermore, Turkmen gas will be distributed nationwide through the inter-province pipeline and connected networks in a number of regions, whereas imported LNG will cover certain limited regions. Moreover, as a result of the expansion in nationwide pipeline networks, pipeline gas, which is domestically produced and imported, will meet LNG in the same consuming area. This evolution of natural gas supply chain – *i.e.* having gas flows from multiple sources – will challenge the rationale of the current price regime in China.

Case study: The Yangtze River Delta Area

The natural gas supply to four provinces in the Yangtze River Delta area (Shanghai, Jiangsu, Zhejiang and Anhui) increased by 42.7%, from 4.46 bcm in 2006 to 6.36 bcm in 2007, and accounted for a 20.6% share of the total natural gas supply in China. At present, natural gas is supplied primarily by the first West-East Pipeline and partially by the sub-sea pipeline from offshore gas fields. Two LNG receiving terminals are now under construction. In Shanghai, the terminal led by CNOOC will be completed in 2009 and will receive LNG from Malaysia's Tiga project, of which the LNG price will be determined by a rather advantageous formula for buyers. In Jiangsu, a new terminal is expected to be opened by 2011 to receive LNG imported by CNPC. CNOOC is also planning to build another

terminal in Zhejiang. Intending to deliver LNG to these two terminals, CNPC and CNOOC signed several long-term LNG contracts in 2008 with QatarGas, Shell and Total.

The price formulae in those contracts are said to be less favorable and close to oil parity. Fortunately, since the oil price has decreased and is currently less than USD 50/bbl, the LNG price under these formulae is calculated as being less than USD 8 per MBtu. However, when the oil price increases again to USD 80/bbl, for instance, the LNG price could attain USD 12.5 per MBtu. When all three terminals are open, total capacity will amount to 9.5 mtpa (12.9 bcm per year). Sinopec plans to supply 1.5 bcm of natural gas to this area through the Sichuan-East Pipeline. The bulk of Turkmen gas will be provided through the second West-East Pipeline after 2010. As examined in the previous section, the price of Turkmen gas at Shanghai city gate could be above USD 10 per MBtu if the import price at Turkmen border is USD 195 per 1 000 m³.

Table 16. Gas Price Estimation in Shanghai (USD/MBtu)

Domestic natural gas		Ex-plant price	Pipeline tariff	City gate price
Offshore (Pinghu)				4.8
1 st West-East Pipeline	Industry	3.7	3.0	6.7
	Residential	2.1	3.7	5.8
	Power	2.1	2.6	4.7
Sichuan-East Pipeline (planning)				6.5-7.5
Natural gas imports		Import (border) price	Tariff* /re-gas cost	City gate price
Malaysia Tiga LNG	Low case (Oil: USD 50/bbl)	6.0	0.8	6.8
	High case (Oil: USD 80/bbl)	8.0	0.8	8.8
QatarGas IV LNG	Low case (Oil: USD 50/bbl)	8.0	0.8	8.8
	High case (Oil: USD 80/bbl)	12.8	0.8	13.6
Turkmenistan Pipeline	Turkmen border: USD 145/1 000 m ³	5.1	3.8	8.9
	Turkmen border: USD 195/1 000 m ³	6.4	3.8	10.2
	Turkmen border: USD 230/1 000 m ³	7.4	3.8	11.2

* The pipeline tariff for 4 000 km of the second West-East Pipeline is estimated at CNY1 000 per 1 000 m³ (USD 144 per 1 000 m³), and the unit tariff per 100 km is calculated to USD 3.6 per 1 000 m³.

Case study: The Pearl River Delta Area

In the Pearl River Delta area (Guangdong Province, Hong Kong and Macau), current natural gas flows through two routes: the sub-sea pipeline from the Yacheng gas field offshore in the South China Sea, which supplies 2.5 bcm of natural gas to Hong Kong, and the Guangdong Dapeng LNG receiving terminal, whose capacity will be expanded from 3.7 mtpa to 5.7 mtpa by 2011. Production in the Yacheng field used to be around 3.0 bcm, but this has recently declined. CLP (the Hong Kong electricity company) planned to build an LNG terminal on the island, but suspended the project in August 2008 because the governments of the mainland and Hong Kong agreed on the long-term supply of natural gas (and electricity) from the mainland to Hong Kong. Macau is also planning to construct an LNG terminal, but has not shown any notable progress as yet.

By contrast, new LNG terminal projects on the mainland seem to have been accelerated. CNOOC is planning a terminal in Zhuhai, and CNPC is reported to have recently started the construction of another terminal in Shenzhen. Total capacity of these three terminals (expanded Guangdong Dapeng, Zhuhai and Shenzhen) has accumulated to 12.2 mtpa (16.6 bcm). CNPC has also launched a second West-East Pipeline to Guangdong and Hong Kong to bring in Turkmen gas. CNPC has another pipeline project of 10 bcm to import natural gas from Myanmar. Sinopec is also planning the Sichuan-South Pipeline. With regard to natural gas demand in this area, the Guangdong government has forecast 25 bcm in 2020 as follows: residential (3.4 bcm); industrial (5.7 bcm); commercial (2.8 bcm)

and power (12 bcm). However, uncertainty of future demand is expanding due to the economic recession in the area.

As for natural gas prices, current end users pay the highest prices in China. In Guangzhou, the capital city of Guangdong, for example, end-user prices are fixed at CNY 3.45 per m³ (USD 13.1/MBtu) for the residential sector, CNY 3.75 per m³ (USD 14.2/MBtu) for the commercial sector, and CNY 4 to CNY 5 per m³ (USD 15 to USD 19/MBtu) for the industrial sector. By contrast, the city gate price is CNY 1.6 per m³ (USD 6.1/MBtu). Power companies paid CNY 1.6 per m³ (USD 6.1/MBtu) for the original long-term based LNG, but had to pay around CNY 5.25 per m³ (USD 20 per MBtu) for additional spot LNG in 2008.

Table 17 Gas price estimation in Guangdong (USD/MBtu)

Domestic natural gas		Ex-plant price	Pipeline tariff	City gate price
Offshore (Yacheng)				3.0
Sichuan-South Pipeline (planning)				6.5-7.5
Natural gas imports		Import (border) price	Tariff /re-gas cost	City gate price
NSW LNG	Low case (Oil: USD 50/bbl)	3.16	0.8	3.96
	High case (Oil: USD 80/bbl)	3.16	0.8	3.96
QatarGasII, IV LNG	Low case (Oil: USD 50/bbl)	8.00	0.8	8.80
	High case (Oil: USD 80/bbl)	12.8	0.8	13.60
Turkmenistan Pipeline	Turkmen border: USD 145/1 000 m ³	5.10	4.6	9.70
	Turkmen border: USD 195/1 000 m ³	6.40	4.6	11.00
	Turkmen border: USD 230/1 000 m ³	7.40	4.6	12.00

*The pipeline tariff for 4 800 km of the second West-East Pipeline is estimated at CNY 1 200 per 1 000 m³ (USD 173 per 1 000 m³), and the unit tariff per 100 km is calculated to USD 3.6 per 1 000 m³.

4.3 Towards price reform

The increase of natural gas imports combined with the multiplication of natural gas supply sources with different prices seems to have pushed the Chinese government towards the reform of the natural gas price regime. In August 2007, the government issued a policy paper that outlined the key aspects of natural gas price reform as follows:

- Simplify price categories and enhance price management.
- Move away from setting prices exclusively and allow the market to play a larger role.
- Rationalise gas prices and link them to the prices of other forms of energy.
- Increase gas prices gradually, eventually linking them to the international market.
- Establish a fully functional price regime for gas.

These principles are, however, rather abstract. Moreover, it does not seem easy to implement the actual reform plan because the government has to balance several stakeholders' costs and benefits. The key question is whether the "allocation and cost-plus" system will be maintained, or changed over to a market mechanism. The current price regime in China has several policy factors such as:

- To ensure gas supply security including upstream development, imports and infrastructure.
- To encourage energy diversification, particularly from an environmental viewpoint.
- To support certain industrial sectors by means of favourable (or subsidised) prices.
- To balance the income gap between urban cities and rural areas.

As examined in the previous section, this regime contains a number of structural defects, particularly with regard to the function for balancing the seasonal, regional and inter-sectoral gap of demand and supply. Thus, a market mechanism should be adopted to resolve this defect. However, China's natural gas market is still developing. For example, a number of rural regions have not yet been connected to

gas supply infrastructure. The question here might be: *Who will owe the cost of infrastructure investment for these regions?* Or, if the sales price were to increase in a certain area due to strong demand, another question might be: *Who should receive the profits among the upstream producers, distribution companies or the local government?*

The work for price reform is likely to be complex because policy makers must consider not only the balance of each market player, but also the role and relation between the central government and the local governments. The most likely reform plan could consist of a mix of the “allocation and cost-plus” base and the market mechanism, which could be outlined as follows:

- A) The central government continues to regulate or set the base line of the city gate prices of inter-provincial pipelines for each city (or province).
- B) City gate prices are determined by the “total cost-plus” base, calculated by the pipeline tariff plus the wedged and averaged cost of total ex-plant prices and import prices of all natural gas flows to the same pipeline.²¹
- C) End-user prices are determined principally based on the market in each region. Excess profits come from the differential between the city gate prices, and the end-user prices will be adjusted by the increase in the city gate prices (or tax).
- D) End-user prices for LNG are determined based on the import price; if the LNG were connected and integrated to the inter-province pipelines, the prices would be the same as in (B).

Very recently, it was reported that the government set up an expert working group to constitute a reform plan. Each stakeholder – including producers, local governments and the association of city gas and industrial users – proposed their respective ideas. In May 2009, a draft on price reform was proposed to NDRC, in which the new natural gas prices would relate to oil prices. The impact of the economic recession may be a negative factor, but the decrease in the international price of natural gas and the reduced concern over inflation in China’s macro economy may provide good timing for gas price reform. Under these conditions, China’s price reform of natural gas could be implemented earlier than most experts anticipate.

²¹ In the simple calculation using the estimated prices in the case study of Shanghai, the city gate prices of pipeline on total cost-plus bases – combined prices of the first and the second West-East Pipeline – will be around USD 8.6 per MBtu in the case of the gas price of USD 195 per 1 000 m³ at the Turkmen border.

5. Gas Security

5.1 Measures for short-term supply disruptions

At present, the response measures and the preparedness for gas supply disruption are insufficient in China, due to the following reasons:

- Natural gas has been a minor or substitution fuel in China.
- Domestic production has virtually been sufficient for domestic demand.
- The infrastructure for natural gas is still under developed in the country.

There is no common national regulation for preparedness, and only a number of voluntary measures have been put in place by producers, distribution companies, users or local governments, preparing for supply disruption caused by unstable production or accidents. For example, Shanergy – a Shanghai electricity company – has a small LNG plant functioning as gas storage, of which the capacity covers two days’ of gas consumption of their power plant, and is now being expanded to 10 days. Shenzhen city has gas stocks capable of lasting for only 19 hours.

Recently, due to the penetration of city gas and the increase of gas-fired capacity, the need for response measures in the case of supply disruptions has been widely recognised. Simultaneously, peak-saving methods have become another serious issue. Several projects for gas storage and pipeline interconnections are currently ongoing. The first underground storage, with a capacity of 1.6 bcm, was built in 2001 and located in the Dagang oilfield in Tianjin, to ensure supply to Beijing and Tianjin. The second underground storage was built in the abundant salt structures in the lower Yangtze valley for the first West-East Pipeline. Three underground storages are now planned to be built alongside the second West-East Pipeline, with a total capacity of 2.5 bcm. According to CNPC’s plans for the future natural gas supply chain, its inter-provincial pipelines are expected to connect to one another, to cover west to north, and north to south in China. CNPC’s LNG terminals in Jiangsu, Dalian and Shenzhen will also be connected to the pipeline network. CNOOC is also planning the construction of an LNG terminal in Zhuhai connected to the expanded pipeline network covering the Pearl River Delta area.²² This increase in interconnection will be a key element to ensure China’s gas supply security.

5.2 Strategy for long-term supply security

The first priority policy for the long-term supply security of natural gas is to increase domestic production. Despite this, China’s import dependence is very likely to increase and may reach 50% by 2020. Thus, it is crucial to secure a long-term and stable supply of natural gas from foreign countries. China’s three major NOCs are responsible for this supply security and have developed stable supply chains from abroad to China, including the construction of infrastructure. The government has supported these activities by diplomatic means and financial support.

The key points regarding China’s strategy for securing long-term and stable gas imports are as follows:

- Long-term supply contracts, and if possible an equity hold over supply sources.
- Stable supply chains, including transportation infrastructure and logistics.
- Regional diversification of supply sources.
- Good relations with gas-exporting countries (and transit countries in the case of pipelines).

As examined in the previous sections, China has obtained several long-term SPAs with LNG sellers from Australia, Indonesia, Malaysia and Qatar, as well as with Shell and Total both of which can provide LNG from their portfolios. Among these projects, China has succeeded in acquiring a 25%

²² CNOOC has another plan to build a coastal pipeline, which will connect all LNG terminals in Guangdong, Fujian, Shanghai and other new ones. However, as far as LNG supply is concerned, it seems more efficient to deliver LNG by ships, which can respond more flexibly to change of demand in each region.

share in Australia's NWS project and a 16.96% share in Indonesia's Tangguh project. CNOOC holds a 25% share in the upstream gas field of Australia's Browse project. With regard to the Queensland Curtis LNG project, CNOOC also agreed to buy 5% of BG's interest of upstream gas field and 10% interest in one of the LNG trains. When China built the first LNG receiving terminal in Guangdong, BP was appointed as the joint-venture partner. After that time, however, Chinese companies have built and operated other terminals by themselves. Even with regard to LNG shipbuilding, China built three LNG vessels by itself with the aim of transporting LNG to Guangdong.

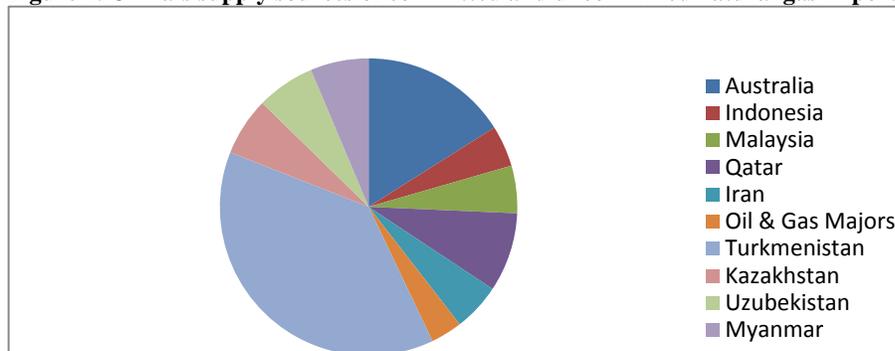
As far as pipeline gas imports from Turkmenistan are concerned, CNPC succeeded in signing a production sharing contract for the upstream gas field and a 30-year SPA. This huge scale pipeline is owned and operated by CNPC in the Turkmen region and by joint ventures with each state-owned entity in Uzbekistan and Kazakhstan. Jointly operating the pipeline with these countries may be an effective way to mitigate the risks of the transit countries. The multi-billion finance extended to by China may promote the project and ensure the stable supply from the project. Generally, in order to enhance NOC foreign investments and infrastructure developments, financial support is being extended by governmental banks, such as China Development Bank and the Export-Import Bank of China.

Geographically, China has an advantageous location, enabling it to have access to foreign natural gas supplies, both by means of marine transport from the Asia-Pacific and the Middle East region, and by pipeline transport from Central Asia and Russia. Figure 7 shows the percentage of committed long-term import sources to China, including unconfirmed agreements (such as HOAs or MOUs),²³ and outlines China's strategy of diversifying gas supply sources. From Australia, the most stable LNG supply country in the Asia-Pacific region and located inside the Malacca Strait, China is importing 4.5 bcm (3.3 mtpa) of LNG, and is willing to increase volumes up to 14 bcm to 18 bcm (11 mtpa to 13 mtpa), supplied by new LNG projects. Both the Indonesian and Malaysian supply sources are also located inside the Malacca Strait.

Faced with LNG tightness, China signed an SPA with Qatar in 2008 – its first long-term LNG agreement with a country in the Middle East. China conducts a diplomatic policy that sometimes differs considerably from that of western countries. With regard to Iran, one of the world's largest gas-holding countries, China has maintained its own diplomatic relations, and has been discussing LNG development in the country. A Chinese government official mentioned that China is concerned about geopolitical risks for the oil and gas supply chain originating in the Middle East and being transported through the Hormuz Strait, the Indian Ocean, the Malacca Strait and the South China Sea, where the United States has a notable military presence. Compared to risks along this "sea lane", pipelines from neighboring countries seem to be favourable for China's energy security. Given this viewpoint, Myanmar is located in a unique position since it can provide natural gas directly to southern China by pipeline.

²³ In this graph, the volume from Turkmenistan is estimated to 30 bcm; those from Kazakhstan, Uzbekistan and Myanmar are estimated at 5 bcm each.

Figure 7. China's supply sources of committed and unconfirmed natural gas imports



Source: IEA

Since China has been focusing on the potential of oil and natural gas in the Central Asian countries, it has worked to improve its political and economic relations with these countries. In 2001, China, Russia, Kazakhstan, Kyrgyzstan, Tajikistan, and Uzbekistan signed the *Shanghai Co-operation Organisation (SCO) Declaration*, which was primarily intended to enforce co-operation on terrorism and separatism in this region. Mongolia, Pakistan, India and Iran joined as observers. Turkmenistan has not yet become a member, but in 2007, the Turkmen president attended the summit. It is thought that China might use this framework to promote political and economic co-operation with Central Asian countries, most of which are oil and gas producing countries and/or pipeline transit countries. In 2006, Russia proposed the creation of an “energy club” – a concept similar to OPEC – under the framework of the SCO. China’s approach has been observed as being slightly different because Sino-Russian relations regarding natural gas transactions are a sensitive issue, and also because China is a gas-importing country. China is also promoting bilateral economic co-operation, including trade expansion, infrastructure building and financial assistance to these countries, including at the most recent meeting of the SCO in June 2009 in Russia.

Russia is the largest and the closest gas-producing country for China. China and Russia have been both very active in seeking natural gas deals in the very heart of Eurasia. China’s bold move to acquire Turkmen gas may apply pressure on Russia in two ways. Firstly, if Turkmenistan can provide the committed volumes of natural gas on schedule, and if China’s domestic production is capable of increasing as anticipated, Russia will lose the opportunity to enter China’s natural gas market during the next decade. Secondly, Russia has to compromise on the deal with Turkmenistan regarding the import price of natural gas to Russia, whilst, at the same time, taking China’s import price for Turkmen gas clearly into consideration. However, it could be a positive factor for Russia that China has shown its acceptance of higher gas prices than Russia initially anticipated. China seems to be moving towards domestic price reform, which is a sign indicating that it intends to accept international gas price levels. China’s future projections of demand and supply contain many uncertainties, including the reliability of Turkmen supply and the potential of domestic production. Recently, China and Russia signed a huge financial agreement for crude oil imports by pipeline from Russia to China. This shows that the geopolitical risk is not an insuperable obstacle for China in proceeding with gas import deals with Russia. China’s regional market situation has clearly been witness to the need for Russian gas, particularly in the northern and eastern parts of the country. Thus, the sensitive game between China and Russia is likely to continue.

6. Implications in the Global Context

Sound evolution of China's natural gas market will have a positive effect on the global environment. The energy diversification from coal to natural gas will reduce marginal emissions of greenhouse gas per unit of energy consumption in China. The utilisation of coalbed methane will also contribute to the reduction of CO₂ emissions and provide CDM opportunities for foreign investors.

In order to render China's natural gas market sustainable, price reform seems to be inevitable. Consequently, China's domestic gas prices should increase and be linked to international prices. The increase and rationale of prices will promote energy efficiency and conservation in China. The development of domestic production could be accelerated by the price increase in both conventional and unconventional gas fields. China's natural gas market will also become more attractive for exporters, both for pipeline gas and LNG. As examined in previous sections, China is expected to become the largest pipeline gas importer and the third-largest LNG importer in the Asia-Pacific region by 2015.

The current situation caused by the global economic crisis is having negative impacts on the growth of China's natural gas market. At the same time, there are several positive factors promoting the evolution of the market. Falling natural gas prices in the international market and disappearing concern over inflation in China's macro economy have provided the opportunity for price reform. It should be noted that the revaluation of Chinese Yuan, which evaluated 15% against the US dollar from 2006-08, has eased the impact of rising import prices on a US-dollar base. China's economic stimulus package, which amounted to CNY 4 trillion (USD 580 billion), is expected to encourage domestic demand and investments for domestic infrastructure, which may have a positive effect on the expansion of the natural gas market.

With regard to its overseas activities, China seems to be accelerating its investments and acquisitions to obtain energy resources abroad, taking advantage of the lower global price of assets and using abundant reserves of foreign currency. China's aggressive investments in oil and gas projects could contribute to an increase in world supply capacity. Still, China should pay careful attention to avoid any increases in tension, which may occur whilst acquiring foreign assets or investing in geopolitically sensitive areas and countries. The increase in energy import dependency may make China more aware of the importance of international supply security than ever before, and enable it to acknowledge the need for co-operation among energy-consuming countries.

Shanghai hub?

The date of the connection of two gigantic pipelines – the Central Asia Pipeline and the second West-East Pipeline (at the end of 2009 or in 2011 at the latest) – will be historically recorded as the first day when natural gas flows on the Eurasian Continent are joined. Gas originating from Turkmenistan will flow both west and east, *i.e.* to the European market and to China. The distance of the pipeline running from Turkmenistan to Shanghai is almost the same, or longer than that of pipelines to Europe. As examined in this report, China's decision regarding the import price of Turkmen gas has already had a certain amount of influence on import prices to Russia, Ukraine and Europe.

Investors in new pipeline projects, such as Nabucco and South Stream, have also had to consider the import price level of the competitor. The import price from Central Asia may become close to the *European Net-back Price*. However, another mechanism, which inland suppliers are appealing for, could be the *Central Asian Net-forward Price*. In turn, this price level could be affected by the *Shanghai Net-back Price*. LNG, the trade of which is becoming more global, and the price of which, is starting to show synchronisation among regional markets, will meet Eurasian Continental pipeline gas in Shanghai and other cities in China. Although the *Shanghai Hub Price* may not appear within the foreseeable future since government price control may remain even after price reform has taken place in China, the international market will pay greater attention to natural gas price trends in China.

Map 4. Linking European and Chinese markets through pipeline imports



Annex 1: References

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Annex 2: Acronyms and Abbreviations

bbbl	barrel
bcm	billion cubic metres
b/d	barrels per day
CESY	China Energy Statistical Yearbook
CBM	Coalbed methane
CDM	Clean Development Mechanism
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CNY	Yuan (Currency of China)
ERI	Energy Research Center
GW	gigawatt
JCC	Japan Crude Cocktail (the average import price of crude oil in Japan)
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas (propane, butane)
MBtu	million British thermal units
mcf/d	million cubic feet per day
mtce	million tonnes of coal equivalent
mtpa	million tonnes per annum
NBS	National Bureau of Statistics, People's Republic of China
NDRC	National Development and Reform Commission
SPA	Sale and purchase agreement
Sinopec	China National Petroleum & Chemical Corporation
tcm	trillion cubic metres
TPEC	Total primary energy consumption
USD	United States Dollar