China's Natural Gas Industry and Gas to Power Generation

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1. Introduction

China's domestic natural gas production has increased from 26.2 Bcm in 2000 to 60 Bcm in 2006 due to progressive exploration and development of the country's natural gas reserves in recent years. In addition to domestic natural gas production, LNG importation projects have also been launched in fast-growing economy areas, such as Guangdong province, Fujian province and the Shanghai municipality.

The 4,000 km West-East natural gas pipeline has also impacted significantly on the market since it went into commercial operation at the end of 2004. Gas consumption jumped from 24.5 Bcm in 2000 to 46.8 Bcm in 2005, an average growth rate of 13.8% per annum. Price difference between low domestic rates and high international rates is also one of the most significant factors behind the rapid increase in gas consumption during this short period.

Despite the fast increase in natural gas production, gas-fired thermal power in 2006 only accounted 1.7% of the nation's total installed electricity generating capacity. In addition, gas-fired power generators have had to face the difficulty of purchasing gas fuel in a period when the gas market has shifted from buyer side to seller side.

Considering the issues of a deteriorating environment, this paper attempts to address the challenges faced by the Chinese government in boosting clean, environment friendly power resources.

2. Overview of China's Energy Supply and Demand

2.1 Energy Supply

According to IEA statistics, the total primary energy supply in China increased from 779 Mtoe in 1994 to 1,388.9 Mtoe in 2004, an average growth rate of 6.0% (see Table 2-1 and Figure 2-1).

Coal is the principal fuel source and accounted for 71.5% of the country's total primary energy supply in 2004, compared to 22.4% for oil, 3.0% for natural gas, 2.2% for hydropower and 0.9% for nuclear power. Coal supply fell between 1997 and 2001, but recovered again from

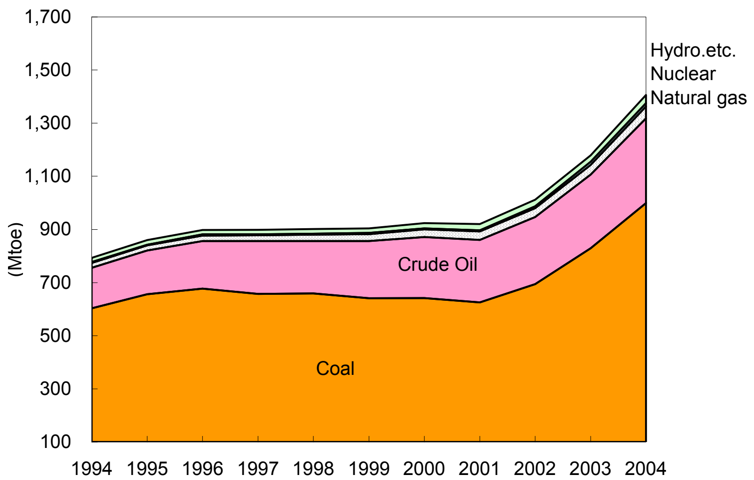
2002 onwards to help fuel the country's spectacular economic growth. Oil output has more than doubled from 145.2 Mtoe in 1994 to 311.3 Mtoe in 2004, but China has become a net importer of crude oil since 1993. Although the share of natural gas in the country's energy mix still remains low, it increased rapidly from 18.2 Mtoe in 1994 to 41.8 Mtoe with an average annual growth rate of 11.9%, and is expected to rise further in the coming years. By 2004, China's eight nuclear power reactors, having a total of 6.31 GW, made up only a small fraction of China's installed generating capacity. However, the government plans to add approximately 30 GW of new nuclear power capacity by the end of 2020. In 2004, China generated 35.2 TWh (or 30.4 Mtoe) of electricity from hydroelectric sources, a large increase over the 1994 figure or even that of 2003 as shown in Figure 2-1, when several big projects such as the Three Gorges Dam and the Ertan Dam came online.

Table 2-1 Primary Energy Supply (1994-2004) Unit: Mtoe

	Coal	Oil	Natural gas	Nuclear	Hydro&etc.	Total
1994	597.7	145.2	18.2	3.8	14.4	779.0
(%)	76.7%	18.6%	2.3%	0.5%	1.8%	100.0%
1999	637.3	204.6	23.8	3.9	17.5	886.4
(%)	71.9%	23.1%	2.7%	0.4%	2.0%	100.0%
2004	992.6	311.3	41.8	13.2	30.4	1,388.9
(%)	71.5%	22.4%	3.0%	0.9%	2.2%	100.0%
Average growth rate (1994/1999)	1.3%	7.1%	5.6%	0.3%	4.0%	2.6%
Average growth rate (1999/2004)	9.3%	8.8%	11.9%	27.6%	11.7%	9.4%
Average growth rate (1994/2004)	5.2%	7.9%	8.7%	13.1%	7.8%	6.0%

Source: *Energy Balances of Non-OECD Countries*, IEA.

Figure 2-1 Primary Energy Supply (1994-2004)

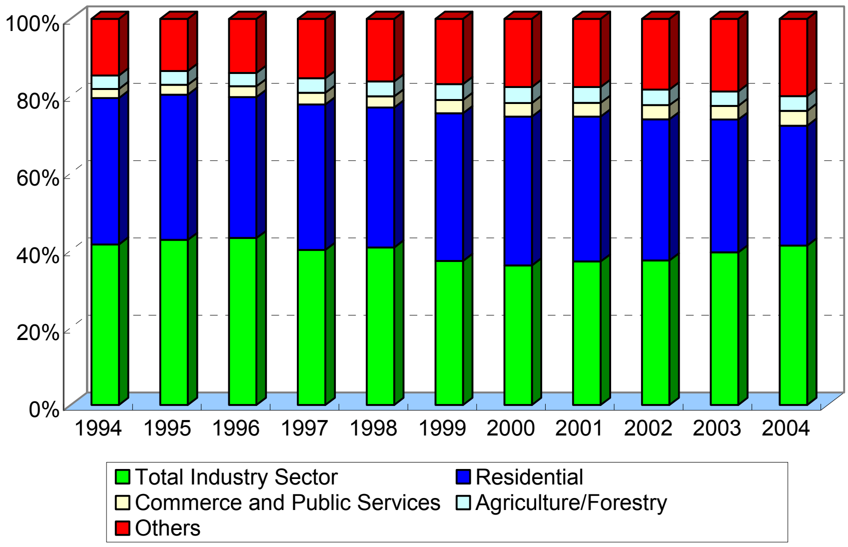


Source: *Energy Balances of Non-OECD Countries*, IEA.

2.2 Energy Demand

Although China's per capital primary energy consumption is lower than the world average, the country has become the world's second-largest energy consumer after the United States. As of 2004, China consumed more than 10% of the world total final energy demand. Total final energy consumption in China in 2004 was 1,038 Mtoe, of which over 33.6% was coal, 24.1% was oil, 14.3% was electricity and just 3.1% was natural gas. The industrial sector alone accounted for 41.3% of final consumption, which is substantially higher than the OECD average. The commercial and residential sectors accounted for 34.9%, and the transport sector accounted for 10.0% of total final energy consumption, respectively (see Figure 2-2).

Figure 2-2 Total Final Energy Consumption by Sectors (1994-2004)



Source: *Energy Balances of Non-OECD Countries*, IEA.

2.3 Outlook for Primary Energy Demand

According to IEA, primary energy demand is projected to grow at 4.0% per annum from 2004 to 2015 and at 2.0% per annum from 2015 to 2030 (see Table 2-2). Total primary energy demand is projected to increase from 1,626 Mtoe in 2004 to 2,509 Mtoe in 2015, and 3,395 Mtoe in 2030. By sector, although growth rate for coal demand between 2004 and 2030 is less than the growth in demand for oil (3.4%) and natural gas (5.1%), coal is still expected to account for 61.0% of total primary energy demand in the year 2030, compared with 22% for oil, 5% for gas, 2% for hydro and nuclear power.

Table 2-2 Outlook for Primary Energy Demand (2004-2030)

	Energy demand (Mtoe)				Shares (%)			Growth (% p.a.)	
	1990	2004	2015	2030	2004	2015	2030	2004/2015	2004/2030
Coal	534	999	1604	2065	61	64	61	4.4	2.8
Oil	116	319	497	758	20	20	22	4.1	3.4
Gas	16	44	89	157	3	4	5	6.7	5.1
Nuclear	0	13	32	67	1	1	2	8.5	6.4
Hydro	11	30	56	81	2	2	2	5.7	3.8
Biomass and waste	200	221	222	239	14	9	7	0.1	0.3
Other renewables	0	0	8	29	0	0	1	-	-
Total primary energy supply	**877**	**1626**	**2509**	**3395**	**100**	**100**	**100**	**4**	**2.9**

Source: *World Energy Outlook 2006*, IEA.

3. China's Gas Industry

3.1 Resources and Reserves

China's main onshore reserves of natural gas are comprised of Sichuan basin, Tarim basin, Ordos basin, Junggar basin and Songliao basin, while offshore reserves are comprised of East China Sea basin, Yinggehai basin and Bohai bay (see Figure 3-1). Recent explorations of natural gas fields have increased the country's proven natural gas reserves significantly higher than those of 1990s. Cedigaz estimates that China holds 2.35 Tcm of proven natural gas reserves as of January 2006 (see Figure 3-2).

Figure 3-1 Natural Gas Reserves in China's Main Gas Basins

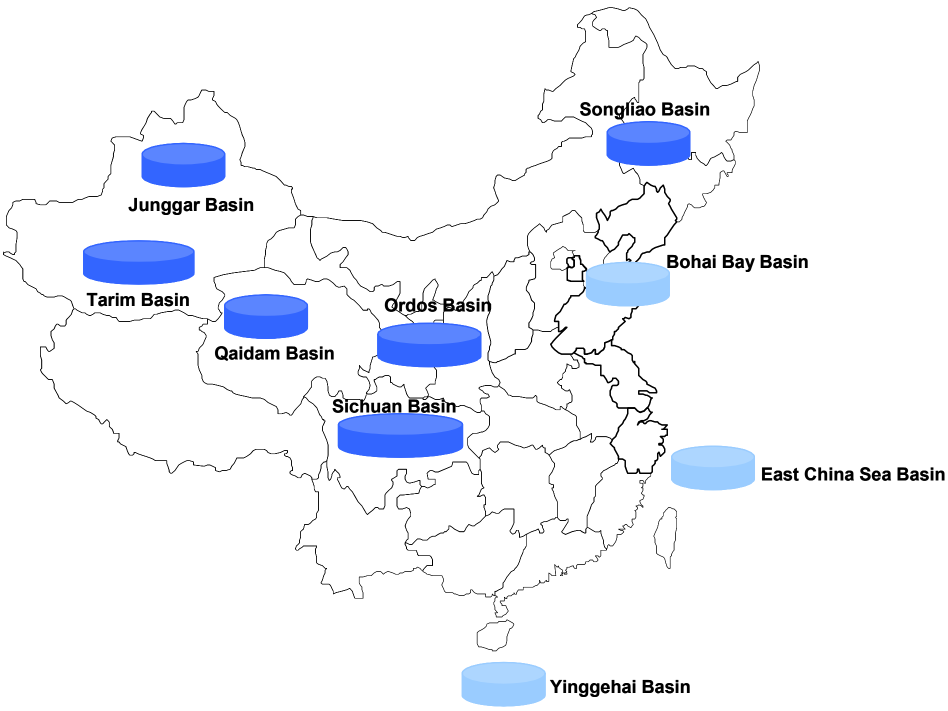
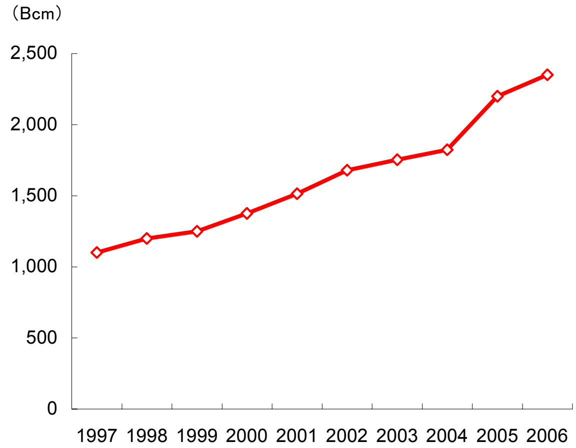


Figure 3-2 Proven Natural Gas Reserves (1997-2006)



Source: *Natural Gas in the World*, Cedigaz.

3.2 Gas Production

In 2006, China's gas production jumped 17.8% above the previous year's output to 59.5 Bcm, a new record for China's gas output. The majority of natural gas production comes from the basins, which are described below.

1) Sichuan basin

The Sichuan basin has the largest output of natural gas and is the area where natural gas was discovered and used earliest in China. In 2006, the production of natural gas in the Sichuan basin reached 13.1 Bcm, accounting for 22.1% of China's total. Proven gas reserves in place at the end of 2004 were more than 800 Bcm and approximately 70% of the resource is located in the eastern and southern parts of the basin.

In April 2006, China Petroleum and Chemical Corporation (Sinopec) confirmed a larger discovery at the Puguang natural gas field in the southwestern Sichuan. The Puguang gas field holds proven recoverable reserves of 356.072 Bcm, the country's second-largest reserve, according to China's State Ministry of Land and Resources. To explore and develop the field, Sinopec will invest 70 billion yuan and expects it to produce 12 Bcm per year by 2008[1].

2) Tarim basin

The Tarim basin is located between Tianshan Mountain and Kunlun Mountain and has an area of 560,000 square km. The basin is estimated to have 724.1 Bcm of proven gas reserves, accounting for 30.8% of the national total. With the progress of exploration technology, output of natural gas in the Tarim basin is expected to continually increase during the Eleventh Five-Year Plan (2006-2010), especially the Kela 2 gas fields, the West-East gas

[1] 1 US $=RMB 7.8 yuan at the time of writing.

pipeline's main source of gas, with proven reserves of 284 Bcm. In addition, a new discovery in Dabei-101well made by Tarim Oilfield Company, one of the subsidiaries of the China National Petroleum Corporation (CNPC), is projected to add 5 Bcm per year to the West-East gas pipeline supply.

3) Ordos basin

The Changqing gas field is one of the main gas fields in the Ordos basin. The proven reserves of its natural gas are 491 Bcm, which accounted for 13.5% of the national total in 2006, making it the third-largest gas field in the country. Meanwhile, Sulige, an other major gas field in Ordos basin, has proven gas reserves of more than 100 Bcm and its production has totaled 590 mln cubic meters since it started operations in November 2006. The field is near the West-East gas pipeline and its output is also transferred through the national trunk gas pipeline. Changbei gas field, which was jointly developed by CNPC and Shell under a production sharing contract between the two companies, went into operation in March 2007, and it is expected to produce an annual natural gas output of 3 Bcm from 2008.

4) Qaidam basin:

The Qaidam basin is located in northwest China and holds proven reserves of 224 Bcm. The basin consists of the main Sebei gas field (Shebei-1, Sebei-2, Tainan) and three other small gas fields. Currently, annual output of natural gas at the Sebei gas field is 2.4 Bcm and is expected to rise to 7 Bcm per year in 2010.

5) Songliao basin:

Although Daqing, China's largest oil field located in Songliao basin, is facing decreasing oil output, the oil field operator CNPC has been relying on natural gas to maintain its production level. By 2005, proven reserves in Daqing hit 400 Bcm and CNPC has set a target of discovering 200 Bcm of new natural gas in the area during the Eleventh Five-Year Plan. Annual gas production at Daqing is forecast to be at 9.5% of its 42 Mtoe by 2010 and 22.5 % by 2020.

6) Junggar basin:

The proven reserves of natural gas in the Junggar basin of Xinjiang Uygur Autonomous Region are about 70 Bcm. The annual output of natural gas produced in 2006 was 2.88 Bcm and is expected to reach 10 Bcm by 2010. The basin consists of three major gas fields, namely Mobei, Mosuowan and Cainan.

7) South China Sea

Development of the Yinggehai basin of Bei Bu Gulf in the western South China Sea has been underway since the middle of the 1990s.

The Yacheng 13-1 gas field was jointly developed by China National Offshore Oil Corporation (CNOOC) (51%), BP (34.3%) and the Foreign Petroleum Exploration Company

(14.7%) and went into operation in January 1996. Its production has been mainly supplied to gas-fired power plants in Hong Kong and chemical factories in Hainan Province.

The proven reserves of natural gas in Dongfang 1-1 gas field, discovered in 1992, are 96.78 Bcm. Operations began there in August 2003. The output of natural gas in this field has supplied power plants, fertilizer and methanol facilities as well as householders in Hainan province. Production there is expected to reach 2.4 Bcm per year from 1.6 Bcm per year at current levels.

The Liwan 3-1-1 Block 29/26 was explored in June 2006 by Husky Energy, a Canadian energy company. The block is located in the Pearl River Mouth Basin and is projected to contain proven reserves of natural gas between 113 Bcm and 170 Bcm.

8) Bohai Bay

The Bohai Bay is situated between Liaodong peninsula and Shandong peninsula and is a large offshore oil and gas field in China. CNOOC has 100% interest in most of the Bay and the company's Boxi block (Qikou 18-1 and Qikou 17-1) and Bonan block (Bozhong 26-2 and Bozhong 28-1) are now operating.

9) East China Sea

The Pinghu oil and gas field was the first comprehensive oil and gas field discovered and developed in the East China Sea. It has a total area of 240 km. The first-phase development project was completed in 1999 and natural gas from there started to be supplied to Shanghai in April the same year. The second-phase went on-stream in November 2006, and this increased supply to 2.0 MMcmd from 1.2 MMcmd. The field, which holds proven reserves of 26 Bcm, is jointly operated by CNOOC (30%), Sinopec Star (30%) and Shanghai Power and Gas (40%).

In July 2006, CNOOC started operation at Chunxiao (or Shirakaba as it known in Japanese) gas field in territory which is claimed by both China and Japan. The gas field is cooperatively operated by CNOOC and Sinopec and output supplies coastal cities of Zhejiang province such as Zhenhai and Ningbo.

3.3 Gas Producers

The natural gas industry in China is dominated by the three large state-owned oil and gas holding companies, namely CNPC, Sinopec and CNOOC.

All three companies operate numerous local subsidiaries, CNPC operating primarily through its chief subsidiary PetroChina. In terms of reserves and production, CNPC is the largest natural gas supplier by virtue of its holding a considerable interests in the central regions of China (Sichuan basin, Ordos basin, Qaidam basin) and in western regions of China (Tarim basin, Junggar basin, Turphan-Hami basin) through PetroChina.

As Table 3-1 shows, CNPC produced 43.87 Bcm in 2006, accounting for 73.7% of the national total. Meanwhile, CNOOC produced 8.4 Bcm of natural gas or 14.1% of the total, followed by Sinopec's 7.25 Bcm of gas output, or 12.2% of the total.

Table 3-1 Natural Gas Production by Producer (2000-2006)

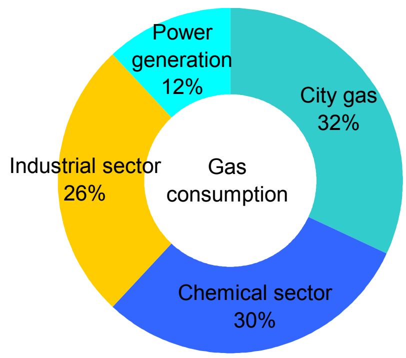
	2000	2001	2002	2003	2004	2005	2006
CNPC							
Daqing	2.30	2.40	2.02	2.03	2.03	2.44	2.45
Liaohe	1.15	1.27	1.13	1.05	1.00	0.92	0.89
Huabei	0.44	0.52	0.53	0.57	0.58	0.57	0.55
Dagang	0.40	0.42	0.39	0.35	0.34	0.33	0.36
Xinjiang	1.62	1.90	2.02	2.21	2.56	2.90	2.88
Tarim	0.75	1.18	1.09	1.09	1.36	5.68	11.01
Turpan-Hami	0.92	1.09	1.14	1.23	1.34	1.53	1.67
Sichuan	7.99	9.08	8.75	9.19	9.78	11.63	13.13
Changqing	2.06	3.68	3.91	5.18	7.45	7.53	8.02
Qinghai	0.39	0.64	1.15	1.54	1.79	2.12	2.45
Yumen	0.02	0.04	0.06	0.03	0.02	0.08	0.08
Jidong	0.06	0.06	0.04	0.04	0.06	0.08	0.10
Jilin	0.20	0.22	0.22	0.23	0.25	0.27	0.28
Total of CNPC	**18.30**	**22.50**	**22.45**	**24.74**	**28.56**	**36.08**	**43.87**
Sinopec							
Shengli	0.69	0.91	0.75	0.81	0.89	0.88	0.80
Zhongyuan	1.34	1.60	1.61	1.70	1.75	1.66	1.60
Henan	0.05	0.09	0.11	0.10	0.10	0.10	0.08
Jianghan	0.09	0.08	0.13	0.10	0.11	0.12	0.12
Jiangsu	0.02	0.03	0.02	0.03	0.05	0.06	0.06
Yunnan/Guizhou/Guangxi	0.08	0.09	0.07	0.09	0.10	0.08	0.06
Sinopec Star	1.65	2.19	2.30	2.36	2.66	3.20	4.28
Others			0.13	0.15	0.17	0.18	0.24
Total of Sinopec	**3.93**	**5.00**	**5.09**	**5.34**	**5.83**	**6.29**	**7.25**
CNOOC,etc.	**3.96**	**5.85**	**5.31**	**4.22**	**6.39**	**8.12**	**8.40**
Total of the Nation	**26.20**	**33.35**	**32.87**	**34.32**	**40.78**	**50.49**	**59.52**

Source: *East and West Report*, March 8, 2007.

3.4 Gas Consumption

In 2005, natural gas consumption increased by 22.3 Bcm from 24.5 Bcm in 2000 to 46.8 Bcm in 2005, an annual growth rate of 13.8%. Of this city gas accounted for 32%, the chemical sector 30%, the industrial sector 26% and power generation 12% as shown in Figure 3-3. Until recently, the chemical sector, in particular fertilizer factories, was the largest consumer. However, since the inauguration of commercial operations of the West-East natural gas pipeline, the share of gas consumption has gradually shifted from the fertilizer industry to city gas users and it is expected that they will be the main consumers of China's natural gas output in the near future.

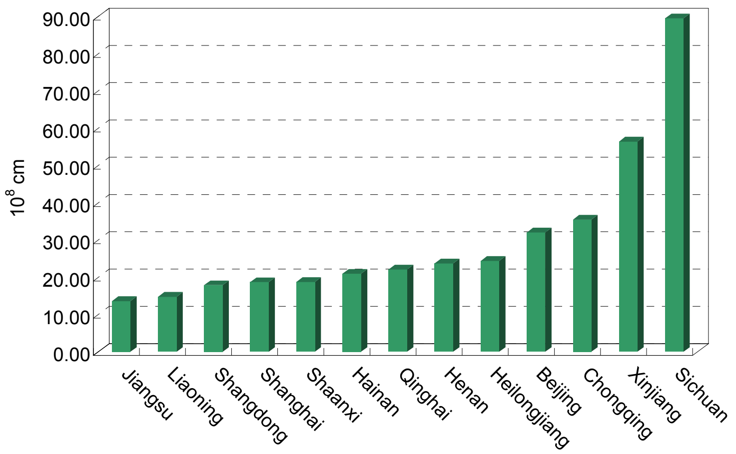
Figure 3-3 Natural Gas Consumption by Sector



Source: *China's Natural Gas Industry and Its Development Strategy*, Nov. 2006, NDRC.

In 2005, there were 13 provinces where annual natural gas consumption reached above 1 Bcm as shown in Figure 3-4. By geographical regions, northwest China, mainly Sichuan province and Chongqing municipality, is the largest consumer region, and it accounted for 29.4% of the total national consumption. The second largest gas consumer region is northwest China, mainly the Xinjiang Autonomous Region, which accounted for a further 24.4% of the total. Meanwhile, although the east China region only accounted for 11.6% of the total consumption, it is the fastest growing region with an annual increase in consumption of 49.1% between 2000 and 2005.

Figure 3-4 Province with Gas Consumption above 100 Million Cubic Meter (2005)

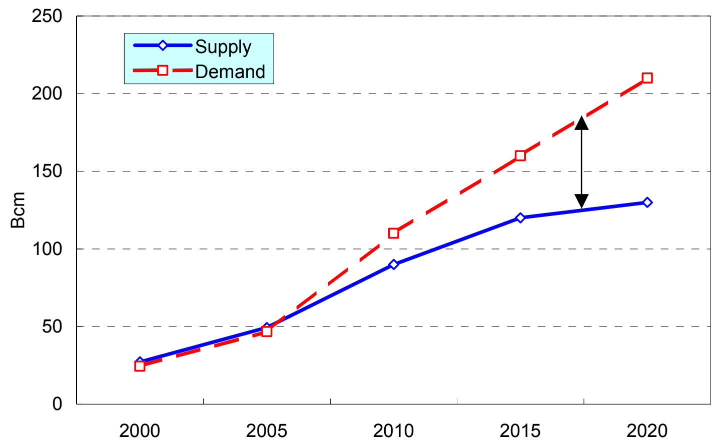


Source: *China Energy Statistical Yearbook 2006*, China Statistics Press.

3.5 Gas Supply and Demand Forecast

According to the NDRC, natural gas demand is projected to reach 210 Bcm per annum by 2020, while domestic supply is projected to provide 180 Bcm only per annum, which implies the imbalance needs to be either filled by piped gas or LNG imports as shown in Figure 3-5. By sector, the share of power generation and city gas is projected to reach 26% and 36% respectively by 2020, whereas by the same date the share of industrial and chemical users is expected to be reduced to 23% and 15% respectively.

Figure 3-5 Gas Supply and Demand Forecast



Source: National Development and Reform Commission.

3.6 Natural Gas Pipeline

By the end of June 2006, China's total length of high-pressure natural gas pipelines reached 24,000 km, yet much of the natural gas is still consumed in the local natural gas producing regions. Currently, the southwest region (Sichuan province), which has a large portion of China's proven reserves, is the largest natural gas consuming territory, due to the lack of cross-regional transport networks. Driven by the rapid growth of gas demand in eastern and southern parts of China, the industry has undertaken efforts to upgrade the gas transportation infrastructure to enable gas be piped from remote basins to developed cities.

Existing and projected natural gas pipelines are summarized as follows:

1) Existing gas pipelines (Since 1996)

   a. Yacheng-Hong Kong: The pipeline went into operation in 1996. It transports natural gas from the Yacheng gas field off Hainan Island to power plants in Hong Kong via a

775 km pipeline and to fertilizer factories in Hainan via a shorter line.

b. Tazhong-Lunnan: The 315 km, 426 mm gas pipeline connected Tazhong 4 gas field in Tarim basin to Lunnan in Xinjiang in 1996. The pipeline has a capacity of 0.7 Bcm per year.

c. Sebei-Golmud: A 189 km pipeline starting from Sebei gas field to the city of Golmud Qinghai province also went into operation in 1996. The pipeline has capacity of 0.8 Bcm per year.

d. Shanshan-Urumqi: A 302 km pipeline from Shanshan in Turpan basin to Urumqi in Xinjiang Autonomous Region went into operation in March 1997. The total length of the pipeline is 302 km.

e. Shanjing (Jingbian-Beijing): A 853 km pipeline from Jingbian in Shanxi province to Beijing began operation in 1997. It transports gas produced in the Ordos basin to industrial and residential consumers in Tianjin and Beijing.

f. Jingbian-Xian: A 488 km pipeline, starting from Jingbian and ending in Xian, Shanxi province, went into operation in 1997. The capacity of the pipeline is 0.5 Bcm per year.

g. Jingbian-Yinchuan: A cross-province pipeline starting from Jingbian in Shanxi province to Yinchuan in Ningxia autonomous has a total length of 320 km and a capacity of 0.6 Bcm per year. The pipeline became operational in 1997 and has supplied gas from Changqing gas field to fertilizer factories and residential consumers in Yinchuan since then.

h. Pinghu-Shanghai: A 375 km pipeline linking Pinghu gas field to Shanghai started operation in 1999. It has a capacity of 0.66 Bcm per year.

i. Sebei-Lanzhou: Construction of a 953 km pipeline started in 2000 and was completed in 2001. It connects Sebei gas field in Qaidam basin to the city of Lanzhou and has a capacity of 2 Bcm per year.

j. Ordos-Hohhot: The construction of this 506 km pipeline was finished in September 2003 and connects Changqing gas field in the Ordos basin to Hohhot city in the Mongolian Autonomous Region. It is expected that the final capacity of the pipeline will reach 1.3 Bcm per year from the current 0.95 Bcm per year.

k. West-East: A 3,900 km pipeline linking Tarim basin to Shanghai began operation in January 2005. The capacity of the pipeline is expected to increase from a current level of 12 Bcm per year to 17 Bcm per year by the end of 2010.

l. Zhongwu (Zhongxian-Wuhan): A pipeline from Zhongxian in Chongqing, Sichuan province, to Wuhan in Hubei province went into operation in January 2005. Total length of the trunk line is 675 km and its annual transport capacity is 3 Bcm. A branch pipeline to Changsha, Hunan province, is expected to be built in 2008.

m. Shanjing II: Parallel with the existing Shanjing pipeline, the Shanjing II pipeline from Yulin via Shangdong, Heibei, Tianjing, Shangdong provinces to Beijing went into operation in July 2005. The total length of this pipeline is 860 km and it has a capacity of 12 Bcm per year.

Table 3-2 Major Pipeline Infrastructure in China

Pipeline/Route	Length (km)	Capacity (Bcm/year)	Year of commercial operation
Major existing pipelines			
Yacheng 13-1-Hong Kong	778	2.9	1996
Tazhong-Lunnan	315	0.7	1996
Seibei-Golmud	189	0.8	1996
Shanshan-Urumqi	302	N.A.	1997
Shanjing (Jingbian-Beijing)	853	2.0	1997
Jingbian-Xi'an	488	0.5	1997
Jingbian-Yinchuan	320	0.6	1997
Pinghu-Shanghai	375	0.7	1999
Sebei-Lanzhou	953	2.0	2001
Ordos-Hohhot	506	1.0	2003
West-East	3,900	12	2005
Zhongxian-Wuhan	760	3.0	2005
Shanjing II	920	3.0	2005
Plans of domestic pipelines			
Daqing-Harbin	78	5	2007
Daqing-Qiqihaer	148.8	N.A.	2007
Yulin-Shandong	1,045	N.A.	2008
Sichuan-West (Puguang-Shanghai)	1,702	12	2010
West-East II	7,700	30	2010

2) Projected Pipelines

a. Daqing-Harbin: The construction of a 78 km pipeline from Daqing oil field to Harbin was launched at the end of 2006. The pipeline will have a capacity of 5 Bcm per annum and is expected to carry natural gas in October 2007. The pipeline also is expected to connect from Harbin to Beijing to shape the country's "North-to-South" natural gas transport project.

b. Daqing-Qiqihaer: Total length of the pipeline from Daqing oil field to Qiqihaer is 148.8 km. It is scheduled to go on operation at the end of 2007.

c. Sichuan-East: On the heels of its large Puguang natural gas discovery in 2002, Sinopec plans to build a pipeline from its Puguang gas field to Shanghai via Chongqing, Hubei, Jiangxi, Anhui, Jiangsu and Zhejiang provinces. The 1,702 km pipeline will have an annual capacity of 12 Bcm with maxium capacity projected to reach 15 Bcm per annum. Construction is expected to start from 2008 and to be completed in 2010. According to Sinopec, the annual output at Puguang gas field is expected to reach over 10 Bcm at the end of 2008 and 15 Bcm by the end of 2009.

d. West-East II: Construction of a second West-East pipeline is on the agenda of China's Eleventh Five-Year Plan. According to CNPC, the pipeline will run 7,700 km from Xinjiang to Guangdong, carrying 30 Bcm of gas a year. The pipeline will run parallel with the first West-East pipeline between Xinjiang and Guansu and branch lines will also be built to connect the two West-East pipeline and gas fields, forming a cross-national natural gas network. CNPC will start by laying a pipeline in Xinjiang in August or September next year and the project is expected to be completed in 2010.

3) Cross-country gas pipeline projects

In addition to expanding the domestic pipeline infrastructure and to diversify its gas supply sources, China has been looking to build cross-country pipelines with several neighboring gas-rich countries. However, due to the gulf in price differences between domestic and international markets and issues of geopolitics, it will take some time for China to reach its cross-border pipeline concepts or projections.

a. Russian-China: During Russian President Putin's meeting with China's Hu Jintao in April 2006, Russian's gas giant Gazprom and CNPC signed a protocol on gas supplies from Russia to China. The protocol covers a time frame, volume and routes of gas supplies and a gas price formula. The projected Sino-Russian gas pipeline is composed of two routes. The Altai gas pipeline is considered the principal one. It is the western route to connect gas deposits in West Siberia with China's Xinjiang Uygur Autonomous Region where it will link up with China's main West-East pipeline. The pipeline will have a total length of 3,000 km and has a designed capacity of 30 Bcm per year. The second pipeline is designed to connect eastern Siberia (Kovykta) and Sakhalin Island with China's Heilongjiang province. Together these pipelines will transport total of 60 Bcm of natural gas a year and are expected to start operation in 2011. However, price issues have reportedly disrupted the negotiations between Gazprom and CNPC and no firm decision has yet been made to proceed with the projects.

b. Turkmenistan-China: During visiting to China in April 2006, President Saparmurat Niyazov of Turkmenistan signed an agreement with the Chinese government allowing CNPC to explore natural gas in the right bank of Amu-Darya River (eastern Turkmenistan) and to construct a pipeline to link the two countries. There is no detailed route mentioned in the agreement, but the pipeline will transverse Uzbekistan and

Kazakhstan to the Tarim basin, which is the start point of the West-East pipe line. Under the agreement, Turkmenistan will supply 30 Bcm of gas annually through a 7,000 km pipeline to China over a 30-year period, starting in 2009. In May 2007, CNPC has reportedly signed a $1.5 billion contract with Turkmenistan on natural gas exploration, which might provide Turkmenistan with sufficient natural gas to export it to both Russian and China[2].

c. Kazakhstan-China: A feasibility study for a project to pipe Kazakh natural gas to China has been undertaken following the completion in December 2005 of an oil pipeline linking the two countries. The proposed Kazakhstan-China natural gas pipeline is designed to transport natural gas from Kazakhstan to the Tarim basin in Xinjiang Uygur Autonomous Region and might also be connected with the above Turkmenistan-China pipeline. The initial gas supply capacity of the pipeline will be 10 Bcm per year and it is expected to start operating in 2009. The capacity of the pipeline will be boosted to 30 Bcm per year in the second phase, which is slated to become operational in 2012.
d. Uzbekistan-China: China and Uzbekistan have reached an agreement on the construction and exploration of a 530 km gas pipeline during the visit by Minister Ma Kai of NDRC to Uzbekistan in April 2007. The capacity of the proposed pipeline is 30 Bcm per year and two compressor stations will also be added to the construction. Details such as the cost of construction and the schedule of operations have not been clarified.
e. Myanmar-China: In January 2007, CNPC signed production contracts with Myanmar's Ministry of Energy covering crude oil and natural gas exploration projects in three deep-water blocks off the western Myanmar coast. A feasibility study for the construction of a gas pipeline from Myanmar to Yunnan province has also been launched by CNPC and the Myanmar Oil and Gas. The pipeline reportedly will transport 170 Bcm of natural gas per year from the Middle East to Southwest China sometime in the next 30 years. A timetable for completion of construction has not been provided.

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[2] In 2003, Turkmenistan and Russia signed a 25-year "gradual increase" contract, which enables Gazprom to purchase gas from Turkmenistan commencing with approximately 7 Bcm in 2005 and increasing to 70-80 Bcm annually by 2008. The deal was reaffirmed by Niyazov's successor, President Gurbanguly Berdimuhammedow and President Putin in May 2007 during Putin's visiting to central Asia. Therefore, Turkmenistan's exiting contracts for gas supply to Russia and other countries will take precedence over the export project to China and whether Turkmenistan still has sufficient gas volumes to meet China's targets is uncertain.

3.7 Gas Storage Facility

1) Dagang

The first gas storage facility at Dazhangtuo in the Dagang oil field, north China, was built in 2004 by CNPC to shave peak gas supply in Beijing and Tianjin. The facility is a little over 2,200 meters underneath the gas field. Following the Dazhangtuo, five more gas storage facilities (Ban-876, Banzhongnan, Banzhongbei, Ban-808, Ban-828) were built by the end of 2006.

2) Jintan

Jintan gas storage facility is in a salt cavern at the eastern end of the West-East pipeline and began operation in February 2007. The underground cavern has a capacity of 4.65 Mcm and is part of a giant storage depot, which will be able to hold 760 Mcm of gas by 2010. The cavern is located at Jintan in Jiangsu province. The facility is designed to store surplus gas when demand falls in the summer and to ease shortages when demand increases in the winter.

3.8 LNG Terminals

To meet the rising domestic demand for natural gas, LNG terminals and LNG imports have been planned by the three major oil and gas companies. Along with the existing operating Guangdong LNG project, LNG terminals are under construction in Fujian and Shanghai and a other LNG terminals are either proposed or planned. Major ongoing LNG terminal projects are summarized below (see Figure 3-6, Table 3-3).

Figure 3-6 LNG Terminals in China

Note: Terminals, which are under construction and are pre-approved are also included.

Figure 3-7 Gas Pipeline Infrastructure in China

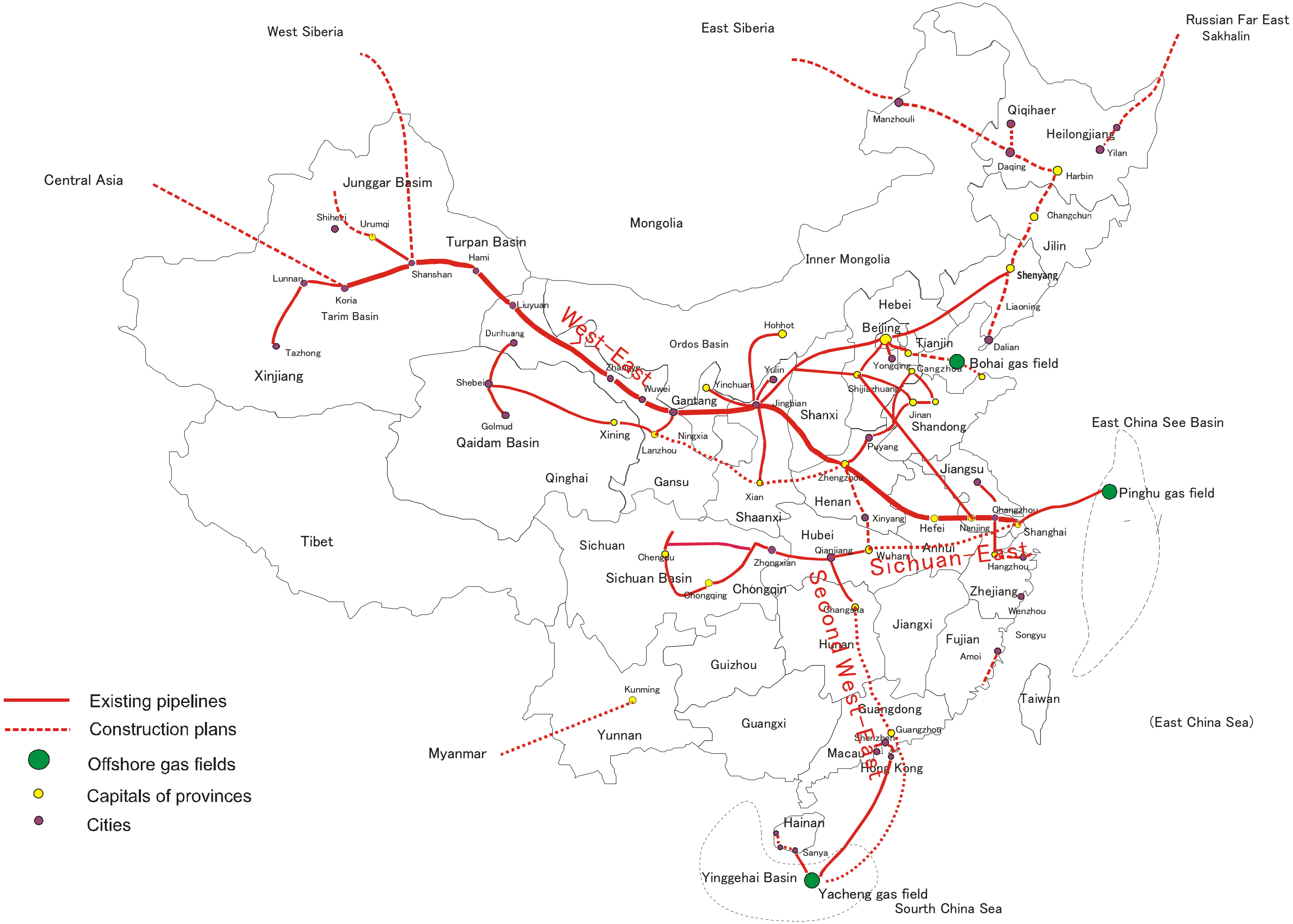


Table 3-3 LNG Terminals in China

	Start-date of commerical operation	First phase Volume (mtpa)	Operators	Sources	Status
Dapeng, Guangdong	2006	3.7	CNOOC(33%),BP(30%), others(37%)	NWS, Australia	Under operation
Putian, Fujian	2007	2.6	CNOOC(60%), FIDC(40%)	Tangguh, Indonesia	Under construction
Yangshan, Shanghai	2009	3.0	CNOOC(49%), Shenergy (51%)	Tiga, Malaysia	Under construction
Rudong, Jiangsu	2011	3.0	PetroChina(55%), POG(35%), JUIG(10%)	-	Approved
Ningbo, Zhejiang	2008	3.0	CNOOC(51%), ZEG (29%), NEPD(20%)	-	Pre-approved
Qingdao, Shandong	-	3.0	SINOPEC&China Huaneng	-	Pre-approved

1) Guangdong Dapeng LNG Terminal

The project is jointly operated by CNOOC, BP and local firms through their joint venture company, Guangdong Dapeng LNG Company Ltd. CNOOC and BP hold 33%, 30% of the shares of the newly-established company, respectively while the remaining 37% are held by the local interests.

The project includes the Dapeng re-gasification terminal, a pipeline distribution network, power plants and town gas companies, being developed in two phases. The first phase involves the construction of an LNG import terminal, two LNG storage tanks, a re-gasification plant, associated marine engineering works and a 385 km LNG transferring trunk line system. Phase I was completed in May 2006 with a 3.7 million ton annual capacity.

The first shipment of LNG from Australia's North West Shelf LNG (NWS LNG) arrived on May 26, 2006. NWS LNG is contracted to ship 3.7 million tons of LNG annually for a 25-year period. 65% of the total LNG is to be supplied to gas-fired power plants and 35% is to be supplied to Shenzen, Dongwu, Guangzhou, Foushan, Huizhou and Hong Kong as city gas.

Table 3-4 Import Volume and Price of Guangdong LNG Terminal

Year	Month	Quantity (mt)	Total value ($)	Average Price ($)	Average price ($/MMBtu)
2006	5	na	na	na	na
	6	57,410	11,390,892	198.41	3.82
	7	62,427	10,238,145	164.00	3.15
	8	0	0	na	na
	9	30,939	5,501,695	177.82	3.42
	10	174,323	28,452,508	163.22	3.14
	11	118,968	19,562,858	164.44	3.16
	12	243,465	40,272,057	165.41	3.18
	1-12	**687,531**	**115,418,155**	**167.87**	**3.23**
2007	1	119,370	19,623,755	164.39	3.16
	2	182,210	30,024,726	164.78	3.17
	3	119,241	19,559,000	164.03	3.165

Source: Platts New, April 16 2007 and etc.

In April 2007, Depeng LNG Co., Ltd. received its first imported spot cargo of LNG. The 60,000 metric tons of LNG was purchased ex-ship from Japan's Mitsubishi Corporation, which purchased the LNG from Spain's Union Fenosa Gas. By May 2007, CNOOC had signed an agreement with Mitsui & Company, Suez, Total SA and Royal Dutch Shell PLC on the spot trading of LNG.

2) Fujian Putian LNG Terminal

Located in the city of Putian, Fujian province, the LNG re-gasification terminal has a Phase Ⅰ capacity of 2.6 million tons of LNG per year and Phase II a capacity of 5 million tons of LNG per year. The construction of Phase Ⅰ started in 2004 and is scheduled to begin operation in 2007.

The terminal is owned and operated by CNOOC Fujian LNG Co. Ltd., a co-investment of CNOOC (60% of the total) and Fujian Investment and Development Corporation (FIDC, 40% of the total).

The LNG Sales and Purchase agreement for the supply of natural gas from BP's Tangguh project in Indonesia was finalized in September 2006 between CNOOC and Tangguh operators. Under the contract, Tangguh will supply 2.6 million tons per year of LNG for 25 years starting from 2009. This will be supplied to gas-fired power plants that will be built during the project's first phase and to householders in five cities (Fuzhou, Putian, Quanzhou, Amoy, Zhangzhou) in the province.

3) Shanghai Yangshan LNG Terminal

The terminal at Yangshan Deep Water Port, south of Shanghai, is operated by CNOOC Gas & Power, a wholly owned subsidiary of CNOON and Shanghai Shenergy Group via a joint venture, Shanghai LNG Co., Ltd. CNOOC has a 45% of interest, while Shenergy has a 55% of stake in the latter.

Construction of the first phase was launched in January 2007 and is expected to be completed in 2009 and to have a capacity of 3 million tons per year. This annual capacity is expected to expand to 6 million tons with the second phase. Total investment of some 4.59 billion yuan will provide for an LNG receiving terminal, an undersea pipeline and several gas-fired power plants.

In July 2006, Shanghai LNG Co., Ltd. signed Sale and Purchase Agreements with Malaysia LNG Tiga Sdn Bhd, a subsidiary of Petronas to import up 3.03 million metric tons of LNG annually for 25 years. Shanghai will receive around 1.1 million tons of LNG in the first three years of the contract with that amount rising to 3 million tons by 2012.

4) Jiangsu Rudong LNG Terminal

The terminal located at Yangkou-port, offshore of Rudong in Jiangsu province is a joint venture by PetroChina (55% of the total share), Pacific Oil and Gas (35%), part of the Singapore-based RGM International, PetroChina and Jiangsu Guoxin Investment Group (10%), a local partner. It is PetroChina's first LNG project and China's second LNG project that is partly owned by a foreign partner.

The project has two phases. In the first phase, the terminal will be built with a capacity of 3.5 million metric tons a year and this is expected to be expanded to 6 million metric tons a year in the second phase expansion. The first phase of the project is scheduled to be finished in the first quarter of 2011.

Negotiation for LNG supply has not yet completed, but it is likely to be sourced from the Middle East or other regions.

5) Zhenjiang Ningbo LNG Terminal

In March 2003, CNOOC signed an agreement with the provincial government to build a LNG terminal in Ningbo, Zhejiang province. The feasibility study for the project was approved by the National Development and Reform Commission (NDRC) in July 2005. The project is composed of a terminal, pipelines and affiliated power plants. The first phase with a capacity of 3 million metric tons a year is expected to be completed in 2008. The capacity is targeted to expand to 6 million metric tons a year.

A joint venture, CNOOC Ningbo Zhejiang Co., Ltd., was established in January 2005 by CNOOC Gas and Power (holding a 51% of total interest), a subsidiary of CNOOC, Zhejiang Energy Group Co., Ltd. (29%) and Ningbo Electric Power Development Co., Ltd. (20%).

6) Shandong Qingdao LNG Terminal

The Qingdao project, located on eastern coast of Shandong province, was agreed in May 2004 by Sinopec and the government of Shandong province. The construction proposal was approved by the NDRC but as yet construction has not been started. The first phase of the project will provide an initial 3 million metric tons per year capacity and this is expected to raise to 5 million metric tons per year.

Possible gas supplying sources to the Qingdao terminal include Indonesia, Yeman, Sahkalin in Russia and Iran.

7) Others

In addition to the above terminals, more than a dozen other LNG terminal projects are either planned or proposed as shown in Table 3-5. However, the government has announced that with the exception of Guangdong only one LNG terminal can be approved in each coastal province. Therefore, some planned projects in Table 3-5, such as Binhai, Jiangsu province are unlikely to be implemented. Furthermore, increasing international LNG prices have affected negotiations between the major Chinese participants and foreign LNG suppliers. Hence, it is unlikely that all these projects can be achieved given the current price gaps between domestic and international LNG markets.

Table 3-5 Other Planned or Proposed LNG Terminals

Site	Scheduled commencement of commerical operation	First phase Volume (mtpa)	Operators
Tangshan, Hebei	2010	6.0	PretoChina, Beijing Holding Ltd., Hebei Construction Investment Co., Ltd.
Dalian, Liaoning	2008	2.0	PetroChina, Dalian city
Tianjin	2010	2.5	Sinopec, Tianjin municipality
Qinhuangdao, Hebei	2010	2.0	CNOOC, Qinghuangdao city
Haikou, Hainan	2009	2.0	CNOOC, Hainan province
Shantou, Guangdong	2010	2.5	CNOOC, Shantou city
Zhuhai, Guangdong	2010	3.0	CNOOC
Guangxi	2010	3.0	PretoChina
Yingkou, Liaoning	-	3.0	CNOOC
Binhai, Jiangsu	-	3.0	CNOOC
Wenzhou, Zhejiang	-	-	CNOOC, Yancheng city
Hong Kong	2011	3.0	CLP

3.9 Natural Gas Pricing

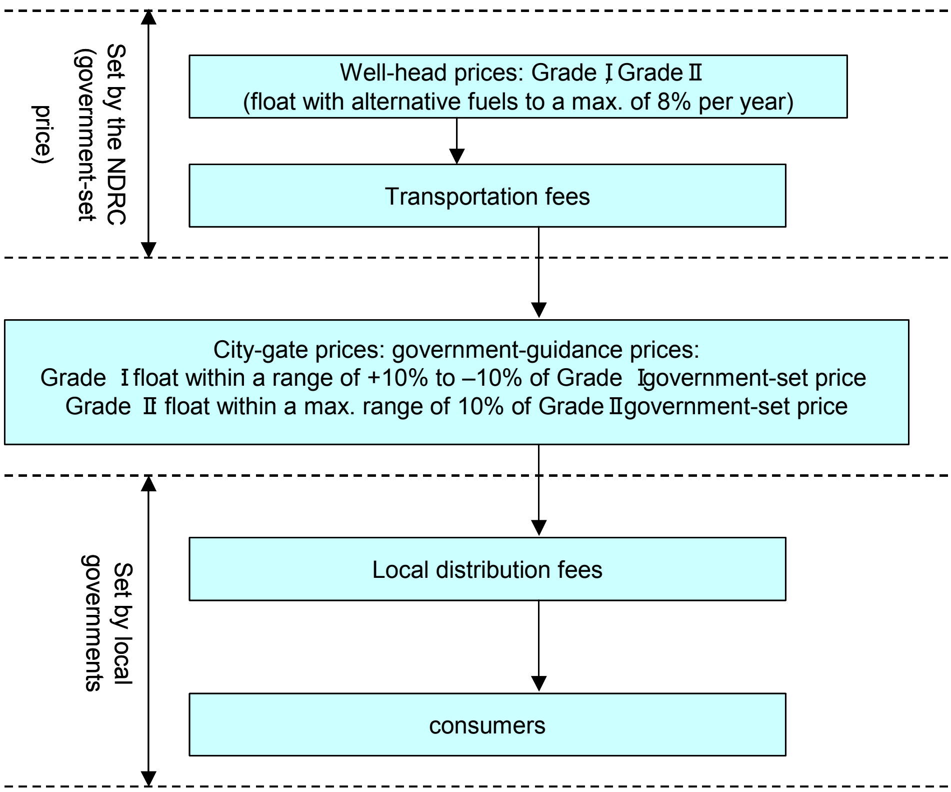
Until recently, well-head prices and consumer prices varied greatly among gas fields. However, in December 2005, the NDRC issued a new directive aimed at reforming the existing natural gas pricing system. The directive aims to establish a market-oriented price mechanism in China’s gas industry and its main points are described as follows:

1) Simplify well-head prices and consumers categories: The directive simplified the plethora of well-head prices into two categories, Grade I and Grade II. Further, each gas field has three different city-gate prices for different consumer categories. The city-gate prices for fertilizer plants are the lowest, while prices set for city gas are the highest in the category as shown in Table 3-6. Production from Grade I well-heads accounts for 85% of the total domestic gas production after the simplification.
2) Shift from a mix of government-set price and government guidance price to government guidance price alone: Government-set price means city-gate gas price including well-head price and pipeline transportation tariff are set by the NDRC, while government guidance price means city-gate price fluctuates within a certain range based on the government-setting price. The former has been applied for the volume of gas sold within the allocated quota, while the latter has been applied for the volume sold above-quota

production (it is also called as "self-sale"). To gradually establish a market mechanism gas pricing, the directive required changing from two-type of city-gate pricing into the government guidance pricing. In detail, city-gate price for Grade I will be settled within a +10% to a –10% fluctuation range of the government-setting price, while the price for Grade II will be set within in a range of 10% fluctuation of the government-set price by the NDRC. There is no price cap for the lowest city-gate price in Grade II.

3) Link well-head price with alternative fuel values: Aiming to form a market-oriented price mechanism in the sector, the government decided to raise the government-set well-head price in line with other alternative resources, namely crude oil, LPG and coal, with a maximum year-on-year adjustment of 8%. The ratio of crude oil, LPG and coal is 40:20:20. Reference to oil price is a weighted FOB price of WTI, Brent and Minas, reference to LPG price is LPG FOB prices in Singapore and reference to coal price is an average price of delivered coal prices from Shanxi, Datong's high grade coal and Shanxi's thermal coal to Qinghuang Island. As there are price gaps between Grade I and Grade II gas fields, price adjustment in linking with alternative fuel resources will firstly be applied for gas fields in Grade II, while the pricing mechanism will be postponed for Grade I for a 3 to 5-year period.

Figure 3-8 Current Gas Pricing System



4) Increase gas prices and reduce price gaps between Grade I and Grade II gas fields: The benchmark for self-sale price is set at RMB 980 yuan per 1,000 cubic meters for Grade II. The benchmark for Grade I will be raised to the Grade II level over three years. Further provision is made to raise prices for fertilizer and city-gate prices for Xinjiang and Qinghai gas fields over a 5-year period. Recognizing comparatively independent gas resources and the long-distances of pipeline transport, the city-gate price for West-East pipeline gas will not be changed during the current period.

In addition, the directive also raised the city-gate prices for industrial and city gas by RMB 50-150 yuan per 1,000 cubic meters, and for fertilizer by RMB 50-100 yuan per cubic meters as shown in Table 3-6

Table 3-6 Government-set City-gate Natural Gas Prices

		Government-set city-gate gas price (RMB/1,000cm)	Government-set city-gate gas price ($/MMBtu)
Grade I			
Sichuan-Chongqing	City gas	920	3.03
	Fertilizer	690	2.27
	Industrial	875	2.88
Changqing	City gas	770	2.53
	Fertilizer	710	2.34
	Industrial	725	2.39
Qinghai	City gas	660	2.17
	Fertilizer	660	2.17
	Industrial	660	2.17
Xinjing	City gas	560	1.84
	Fertilizer	560	1.84
	Industrial	585	1.93
Others (Daguang, Liaohe,Zhongyuan)	City gas	830	2.73
	Fertilizer	660	2.17
	Industrial	920	3.03
West-East(Note)	City gas	1,270	4.18
	Fertilizer	1,120	3.69
	Industrial	1,100	3.62
Grade II (Excluding from Grade I)	City gas	980	3.22
	Fertilizer	980	3.22
	Industrial	980	3.22

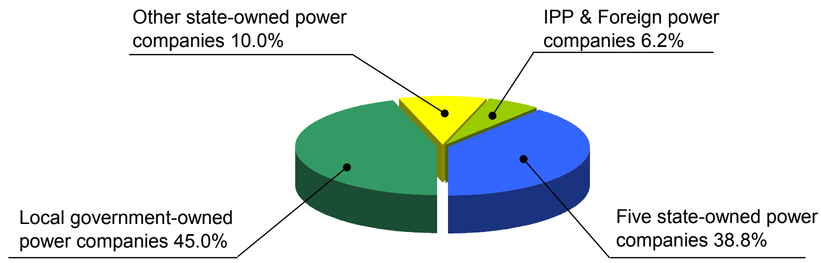
Note: Wholesale price of West-East pipeline gas remains untouched at this stage of the price review.
Source: NDRC.

4. China's Electricity Industry

4.1 Outline of the Electricity Industry Structure

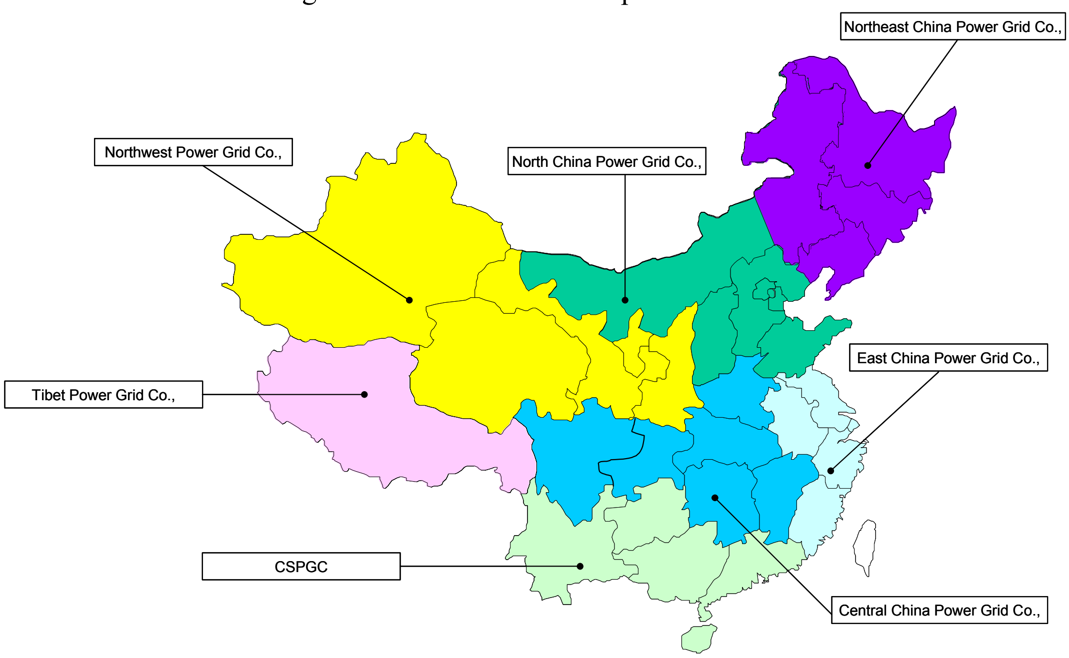
In March 2002, the Chinese government issued a "Plan for Electric Power System Reform" as the State Council Notice [2002] No.5, which was a guiding document for China's electric power system reform incorporating the concept of separating the generation sector from the transmission sector and introducing competitive principles.

Figure 4-1 Share of the Total Installed Capacity by Generators (2006)



Source: *Annual Report of Regulation on China's Electricity Industry 2006*, SERC.

Figure 4-2 Power Network Operators in China

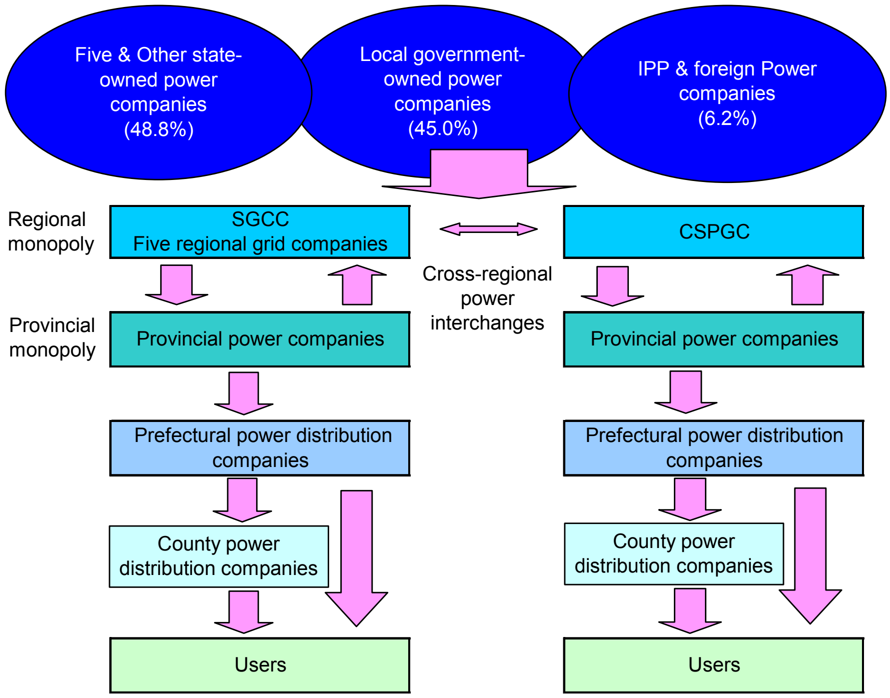


Note: Tibet Power Grid Co., is an independent transmission operator, but currently is temporarily operated by the SGCC.

Based on this plan, power generation assets previously owned by the State Power Corporation of China (SPCC) were restructured into five state-owned holding companies, namely China Huaneng Group, China Datang Group, China Huadian Corporation, China Guodian Corporation and China Power Investment Corporation. By 2006, the five holding companies operated more than 38% of China's installed capacity following the local generators (see Figure 4-1).

Meanwhile, transmission assets were dismantled into the State Grid Corporation of China (SGCC) and China Southern Power Grid Corporation (CSPGC). SGCC consists of North China, Northeast China, Northwest China, central China and East China power networks, while CSPGC covers regional power networks in Yunnan, Guizhou, Hainan and Guangdong provinces (see Figure 4-2).

Figure 4-3 Electric Power Supply System in China

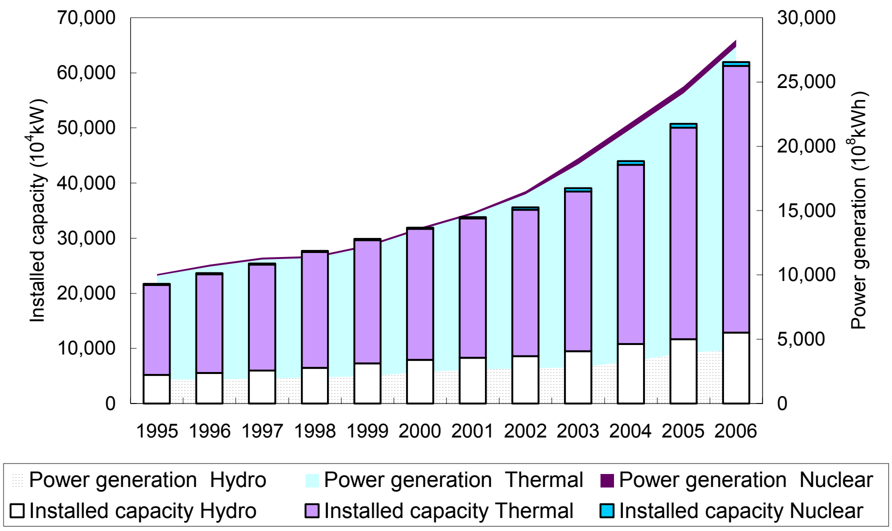


To introduce and implement competition into China's electricity industry, China's first independent regulatory organization-the State Electricity Regulatory Commission (SERC) was also established by the State Council in March 2003 to regulate and monitor the industry.

4.2 Installed Capacity and Power Generation

In 2006, China's total installed generation capacity increased by 101.2 GW to 622 GW, an annual growth rate of 20.3%. Of this, thermal power made up 77.8%, hydropower 20.7%, nuclear power 1.1% and renewable sources made up 0.4%.

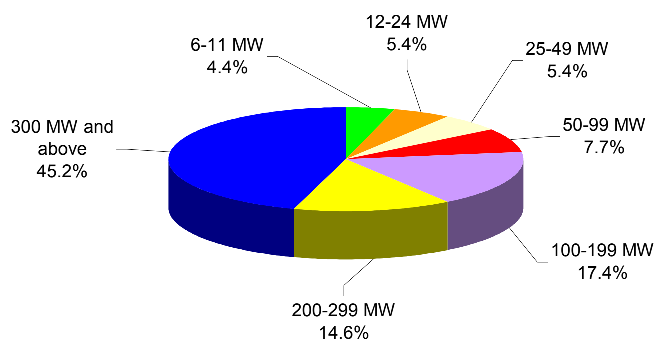
Figure 4-4 Installed Capacity and Power Generation (1995-2006)



Source: China Electricity Council.

In recent years, the percentage of coal-fired power capacity has been continually increased due to high oil prices and severe nation-wide power shortages. In 2006, coal-fired power plants represented more than 86% of the total newly installed capacity. Although 600 MW and above thermal power plants are currently the mainstream of China's power development, 30 MW and below thermal power units still represent a significant amount of the total thermal power units. Figure 4-5 shows that 300 MW and below thermal power units accounted for 54.8% of the total thermal capacity in 2004. Considering certain 130-199 MW thermal power units were built in 2004 and consequently started operation in 2005, the percentage of small-scale thermal power units is unlikely to be changed significantly.

Figure 4-5 Capacity Mix of Thermal Power Units (2004)



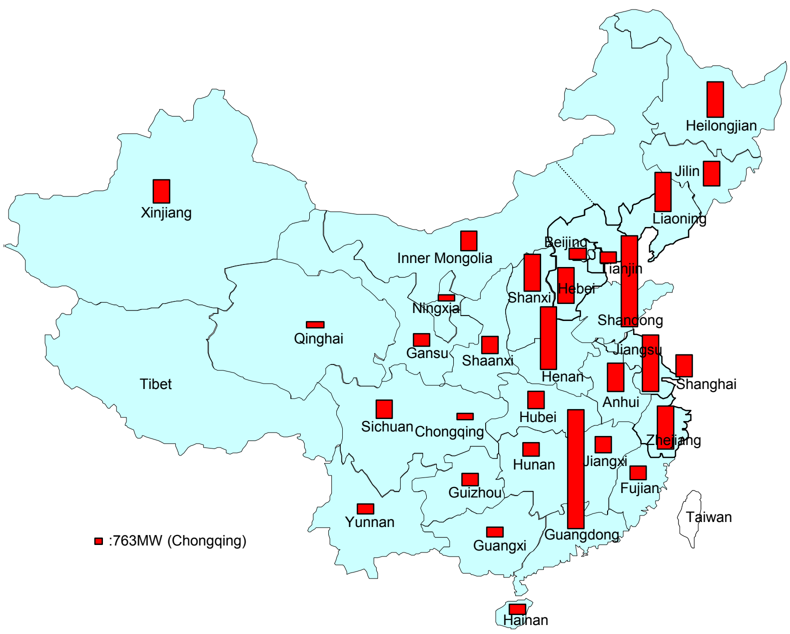
Source: *Electric Power in China 2005*, China Electric Power Information Center.

However, the Chinese government has decided to shut down 100 MW and below small thermal power plants. These represent a total electricity generating capacity of 50 GW between 2006 and 2010, but their lost capacity will be compensated for by a prospective balancing of power demand and supply in the coming years and a strict energy saving targets set in the government's Eleventh Five-Year Plan. To achieve the agenda, the five state-owned power companies and local governments with the majority capacity of installed small-scale thermal power plants have been given compulsory decommissioning targets by the central government (see Figure 4-4). Targets for decommissioning for each state-owned power company and local government are shown in Table 4-1.

Table 4-1 Closure Targets for Small-scale Thermal Power Plants (100 MW and below) by 2010

Power company/Province	Target (MW)	% of Total
Five state-owned power companies	2,226	42.7%
Beijing	60	1.2%
Shanxi	300	5.8%
Shanghai	210	4.0%
Zhejiang	310	5.9%
Shandong	400	7.7%
Henan	360	6.9%
Hunan	100	1.9%
Guangdong	1,000	19.2%
Sichuan	136	2.6%
Shaanxi	110	2.1%
Total	**5,212**	**100.0%**

Figure 4-6 Location of Small-scale Thermal Power Plants (6,000 kW- 125 MW) in 2005



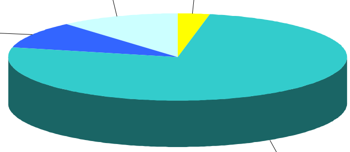
Source: China Electricity Council.

Meanwhile, power generation reached 2,834TWh, an annual growth rate of 13.5% from 2005, 83.17% of this growth was in thermal power, 14.7 % in hydropower and 1.9% in nuclear power.

4.3 Electricity Consumption

Electricity consumption in China averaged a 14.0% increase year on year to reached 2,824 TWh, over a five consecutive year period ending in 2006. As shown in Figure 4-7, 75.6% of the total electricity was consumed by industrial users, due to the continual growth of steel, aluminum, cement sectors and so on. Although residential consumption accounts for the second largest power-consuming sector, it remains far behind that in developed countries, leaving a huge potential for future growth in electricity demand.

Figure 4-7 Electricity Consumption by Sector



Source: *Annual Report of Regulation on China's Electricity Industry 2006*, SERC.

Table 4-2 Electricity Consumption from 2000-2006

		2000	2001	2002	2003	2004	2005	2006
Agricultural	**Consumption (10^8kWh)**	**721.0**	**759.1**	**776.2**	**771.6**	**612.0**	**741.0**	**832.0**
	% of total consumption (%)	5.3%	5.2%	4.7%	4.1%	2.8%	3.0%	2.9%
	Annual growth rate (%)	3.6%	5.3%	2.3%	-0.6%	-20.7%	21.1%	12.3%
Industrial	**Consumption (10^8kWh)**	**9,795.1**	**10,646.4**	**11,957.3**	**13,960.6**	**16,258.0**	**18,478.0**	**21,354.0**
	% of total consumption (%)	72.5%	72.5%	73.0%	73.9%	74.8%	74.8%	75.6%
	Annual growth rate (%)	11.2%	8.7%	12.3%	16.8%	16.5%	13.7%	15.6%
Commerical	**Consumption (10^8kWh)**	**1,300.3**	**1,441.8**	**1,651.3**	**1,931.3**	**2,435.0**	**2,631.0**	**2,822.0**
	% of total consumption (%)	9.6%	9.8%	10.1%	10.2%	11.2%	10.7%	10.0%
	Annual growth rate (%)	0.7%	10.9%	14.5%	17.0%	26.1%	8.0%	7.3%
Residential	**Consumption (10^8kWh)**	**1,692.2**	**1,835.3**	**2,001.4**	**2,230.3**	**2,430.0**	**2,838.0**	**3,240.0**
	% of total consumption (%)	12.5%	12.5%	12.2%	11.8%	11.2%	11.5%	11.5%
	Annual growth rate (%)	15.1%	8.5%	9.1%	11.4%	9.0%	16.8%	14.2%
Total consumption		**13,508.5**	**14,682.5**	**16,386.3**	**18,893.7**	**21,735.0**	**24,689.0**	**28,248.0**

Source: *China Electric Power Industry Yearbook*, China Electric Power Publishing; *Annual Report of Regulation on China's Electricity Industry 2006*, SERC.

4.4 Gas-fired Power Plants

With West-East gas transportation and LNG imports from Australia, the total capacity of gas-fired power plants reached 10,627 MW in 2006, accounting for 1.7% of China's total installed capacity and 2.2% of total installed thermal capacity, respectively. Gas-fired power plants are mainly installed in Shanghai, Jiangsu and Zhejiang where gas is sourced from the West-East natural gas pipeline, and in Guangdong where LNG is sourced from NWS, Australia.

In addition to the above existing gas-fired power plants, 21.8 GW gas-fired power plants are under construction or planned as shown in Table 4-3. China Electricity Council projected that gas-fired power capacity will reach 60 GW accounting for 5-6% of the total installed capacity in China by 2020.

Despite more gas-fired power plants being planned as part of the country's strategy for diversifying electric generation components, China's gas-fired generators are facing critical issues, which are highlighted as follows:

Figure 4-8 Existing Gas-fired power plants in China

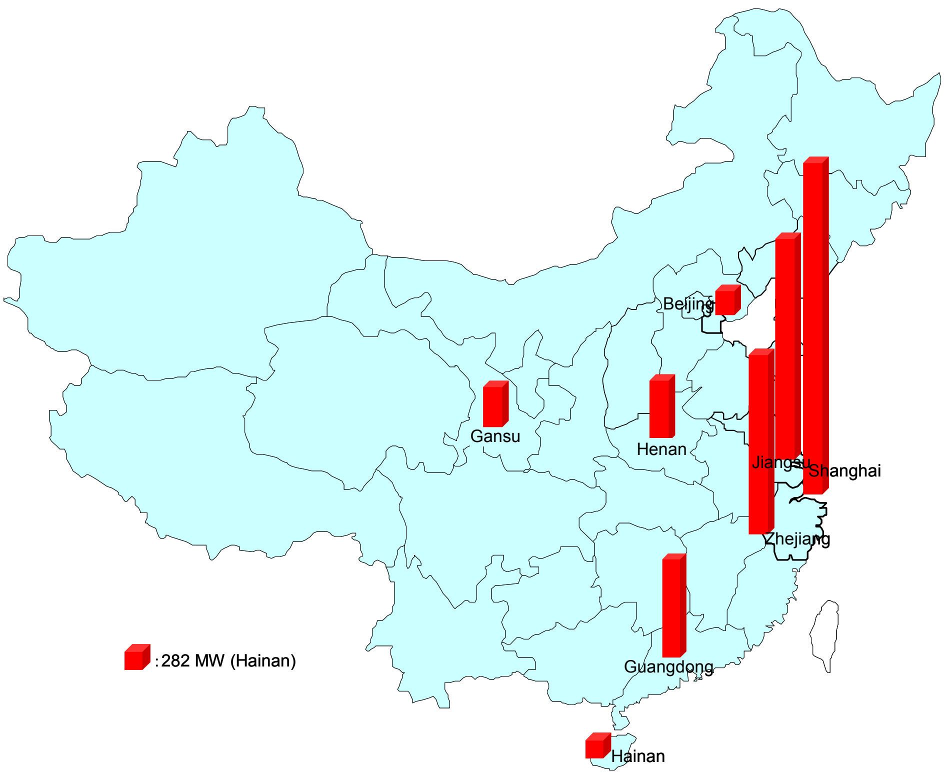


Table 4-3 Gas-fired Power Plants under Construction or Planned

Province	Power Station	Unit Capacity (MW)	Total Capacity (MW)
Shanghai	Lingang	-	1,600
Zhejiang	Xiaoshan	2×350MW	700
	Jinhua	1×150MW	150
	Guohua Yuyao	2×780MW	1,560
Jiangsu	Huaneng Jinling	1×390MW	390
Fujian	Jinjiang	4×350MW	1,400
	Xiamen Dongbu I	2×350MW	700
	Xiamen Dongbu II	2×350MW	700
	Putian	4×350MW	1,400
Guangdong	Shenzhen Dongbu I	2×350MW	700
	Shenzhen Dongbu II	8×350MW	2,800
	Shenzhen Qianwan I	3×350MW	1,050
	Shenzhen Qianwan II	6×350MW	2,100
	Huizhou I	3×350MW	1,050
	Huizhou II	6×350MW	2,100
	Zhujiang I	2×350MW	700
	Zhujiang II	4×350MW	1,400
Henan	Zhengzhou	2×350MW	700
Sichun	Jiangyou	2×300MW	600
Total			21,800

1) Lack of gas fuel for gas-fired power plants

To share the project risks of West-East pipeline and Guangdong LNG imports, gas-fired power plants had been installed extensively in the east coast region (Shanghai, Zhejiang and Jiangsu provinces) and Guangdong province by the end of 2006. However, unexpected escalating gas demand from residential as well as large industrial users has caused a tight gas supply and demand situation just as the West-East pipeline commenced full commercial operation at the end of 2004. The shortage of natural gas has put those gas-fired power plants, which were ready to come on line on the edge of closure. Due to the lack of natural gas supply in Shanghai, gas-fired power plants with a total capacity of 4 GW in 2005 and 6 GW in 2006 failed to generate electricity and to play a role for the expected peak shaving in the region.

2) Lack of competitiveness of gas-fired power plants compared to coal-fired power plants

Although China's coal prices for power plants have been increasing since 2002 and coal prices in the southern region are even higher than that of international coal prices, a gas-fired power plant still finds it difficult to compete with a coal-fired power plant as shown in Table 4-4.

The model for the table assumes a simplified calculation, which does not include factors such as construction cost, depreciation cost, rate of return on capital investment and so on. According to joint research presented by the Energy Research Institute of National Development and Reform Commission and the Power Economic Research Center of State Grid Corporation, the price ratio between natural gas and coal in Guangdong is 2.5:1 and 2.8:1 on the east coast. Both of which are higher than the critical price ratio of 2.4:1[3]. Hence, under the current energy pricing system, a gas-fired power plant is not competitive against a coal-fired one from a cost perspective.

Table 4-4 Assumption for Fuel Cost Comparison between a Coal and a Gas-fired Power Plant

	Gas plant (CCGT)	Coal plant
Fuel cost	1.45yuan/cm	360yuan/ton
Fuel heat value	8,942kcal/cm	7,000kcal/kg
Efficiency	55.4%	35.0%
Fuel consumption per kWh	0.162kg/kWh	0.370kg/kWh
Power generating cost	0.2354yuan/kWh	0.1332yuan/kWh

Source: *China's Natural Gas Industry Report 2006*, HL Consulting.

3) Power Purchase Agreement (PPA) vs. Take-or-Pay

In December 2002, China launched a new round of reform policy in the electricity industry as described above. The purpose of this dynamic reform is to introduce competitive principles, break down the monopoly of the State Power Corporation, and hence reduce wholesale prices in the generation sector, which the government has emphasized since 1997. One of the results of the market restructuring has been the introduction of an annual PPA instead of a long term one and the operational hours of thermal power plants run by a power generating entity are principally based on the generator's wholesale price the PPA provides for. Theoretically, local power grid companies are favored to contract more electricity from cheaper generators without taking the efficiency of their power plants or the environmental premium of a clean-energy source into account[4]. To date, competitiveness has never impacted on generators due to the

[3] The report insists that only when the price ratio between natural gas and coal is less than the critical price of 2.4:1 would a gas-fired power plant be competitive.

[4] Given that the regulation system monitoring PPA procedures is weak and there is a lack of transparency, local power grid companies tend to favor their affiliated power plants (APPs) and local government related power plants, even where some of them have higher generation costs than those from neighboring cities or provinces. In practice, dispatching volumes for old thermal power plants are signed based on their historical performances, whereas, dispatching volumes for new thermal power plants are determined based on the average operational hours of the same type for newly installed power plants in the region. Therefore generation from either old power plants or new ones is dispatched almost equally rather than prioritizing the lowest-cost power or that of the cleanest-generation sources. In addition, acute nation-wide power shortages since 2002 have prevented local power grid companies from making any

nation-wide power shortages.

However, given the huge growth of more than 100 GW in generation capacity installed in 2006, a tremendous construction which is unparalleled in any developed country, the industry has a projected power surplus in certain regions in certain periods in the coming years. Under such circumstances, local power grid companies will either have to reduce the local average dispatching hours signed with generators or force some uncompetitive generators out of the local wholesale market to maintain the balance between power supply and demand. Over and above any projected power surplus, the latest round of market restructuring has been unsuccessful in meeting government expectations, again due to the power shortages. Pilot programs to create power pools launched in Northeast China and East China regions have been both postponed because of the current irrational pricing system, leaving uncertainty about China's power pooling system[5].

Given that gas-fired power plants lack competitiveness vis-a-vis coal-fired ones and that there is a mismatch between the power reform policy and Take-or-Pay contract required by the upstream gas suppliers, local power grid companies will be reluctant to sign any PPA which will allow gas-fired generators to cover their full costs, while gas-fired generators will be unable to fulfill the Take-or-Pay obligations under gas sales contracts. This conundrum might not only jeopardize the business of gas-fired generators but also the whole chain of gas supply.

4) Irrational Electricity Pricing System

China's electricity price can be roughly categorized into a wholesale price, a transmission /distribution price and a retail price. The wholesale and transmission/distribution prices are approved by the NDRC, whereas the retail price is set by the NDRC. The pricing system for wholesale power is based on a "cost plus profit" approach and a "same grid, same price" principle. Since 2002, a uniform wholesale price for similar types of power plants has been introduced with the aim of reducing the high overall cost. This pricing system does not take into account efficiency and environmental performance even among the same types of power plants.

A coal-power price adjustment mechanism was eventually introduced in May 2006, allowing power generators to pass on an increasing coal price in their wholesale rate within a margin of 8%. 70% of any increase in coal price can be added to wholesale price of coal-fired power

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differential APPs among different types of generators. The current situation in the Chinese power sector is that all types of generators can operate their power plants at optimum hours and realize acceptable profit margins.

[5] A power pooling system has also been introduced to South China region and it is still under trial. The major reason for postponing the experiment in Northeast and East China regions is that wholesale prices from the respective pools have been higher than wholesales prices contracted with power grid companies via APPs, whereas, retail prices are controlled by the government. Therefore, the more power purchased from the power pool the more economic losses for local power grid companies. It is unlikely that the power pooling system would be successful if the current power pricing system remains in place and/or power supply is behind demand.

plants and the remaining 30% of the increasing coal price must be absorbed by power generators. The fuel adjustment mechanism targets only coal prices rather than others such as those of natural gas. Given that the government intends to raise the price for natural gas by 8% per annum as described above, gas-fired power generators will have more difficulties competing with coal-fired generators and operating their plants if any increases in gas fuel cannot be included into their wholesale power prices.

To promote the installation of flue-gas desulphurization (FGD) equipment with a view to reducing SO2 pollution, an environment premium has been set at RMB 0.015 yuan per kWh for those coal-fired power plants with FGD compared to those without[6]. However, there are no environmental premiums or taxation preferential policies for gas-fired power plants. As Table 4-5 shows that wholesale price for gas-fired plant in Hainan province is as the same price as coal-fired power plants without FGD.

Table 4-5 Tentative Wholesale Price for New Installed Power Plants (June 2004)

Region	Province	Wholesale price (RMB/kWh)			
		Thermal			Hydro
		Coal-fired power plants		Gas-fired power plants	
		with FGD	without FGD		
North China	Beijing	0.320	0.305	-	-
	Tianjin	0.320	0.305	-	-
	Hebei	0.320	0.305	-	-
	Shanxi	0.250	0.235	-	-
	Shangdong	0.325	0.310	-	-
	Inner Mongolia	0.252	0.237	-	-
East China	Shanghai	0.390	0.375	-	-
	Jiangsu	0.370	0.355	-	-
	Zhejiang	0.400	0.385	-	-
	Anhui	0.345	0.330	-	-
	Fujian	0.365	0.350	-	-
Cental China	Hubei	0.335	0.320	-	-
	Hunan	0.360	0.345	-	0.315
	Jiangxi	0.350	0.335	-	-
	Henan	0.305	0.290	-	-
	Sichuang	0.310	0.295	-	0.280
	Chongqing	0.310	0.295	-	-
South China	Guangdong	0.420	0.405	-	-
	Guangxi	0.335	0.320	-	0.260
	Yunnan	0.255	0.240	-	0.215
	Guizhou	0.250	0.235	-	0.215
	Hainan	0.365	0.350	0.350	0.260

Note: Wholesale prices for Northeast and Northwest regions are not listed in the Table.
Source: *China's Electricity Industry*, Japan Electric Power Information Center.

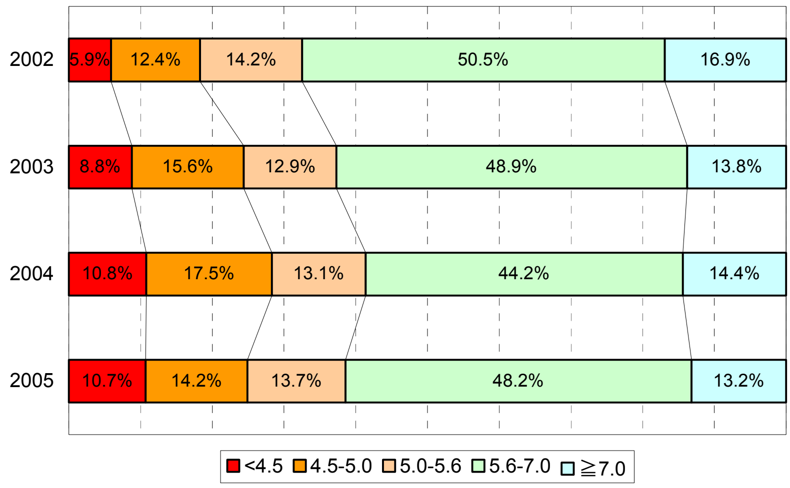
[6] In June 2006, the government raised the premium price from RMB 0.015yuan/kWh to RMB 0.03yuan/kWh.

Therefore, under the current electricity pricing system there is no incentive for generators to build more environmentally friendly power plants with higher efficiency.

4.5 Environmental Issues Arising from the Power Sector

The industry's rapid growth over the last decade has brought tremendous environmental problems, particularly those related to SO2 emissions. In 2005, SO2 emitted by the power sector increase from 9.29 million tons in 2004 to 11.12 million tons, which accounted for 51.3% of the total industry SO2 emission and 43.6% of the national total. The problem associated with the SO2 is acid rain, which is sometimes defined as a pH of less than 5.6. Figure 4-9 shows that cities which pH of rainfall are below 5.6 increased by 6.1% from 32.5% in 2002 to 38.5% in 2005. Cities which pH of rainfall below 4.5 almost doubled from 2002 to 10.7% of major cities, indicating that areas suffering from stronger acid rain has been increased dramatically.

Figure 4-9 The pH of Rainfall in Main Cities (2002-2005)



Source: *China Environmental Annual Statistics 2003-2006*, State Environmental Protection Administration of China.

Although the power sector is the main contributor to the country's SO2 emission and China's acid rain has also damaged its neighboring countries including Japan and Korea, the penetration rate of installed FGD in the power sector remains low. By the end of 2005, the percentage of thermal power plants with FGD only accounted for 13.8% of the total installed capacity of thermal power. In addition, the performance of FGD varies among domestic manufactures and some of FGD have never been fully operated by generators. Some generators have been reportedly stopping running FGD, despite having received the premium price of RMB 0.015 yuan per kWh for power they have sold to the grids. Therefore, the actual operating rate of FGD is significantly lower than it should be and SO2 desulphurized by the power sector in 2005 was only 20.2% of the total SO2 it emitted. Needless to say the power sector is also the primary source of CO2 and contributes to NO_X, yet flue-gas Denitrogen has not yet been introduced in the industry.

5. Implication

There are many advantages to a gas-fired power plant and the reasons for China to build more gas-fired power plants instead of coal-fired power plants have been well presented in the IEA report. In addition to those reasons, this paper emphasizes that current government strategies on energy saving and policies on environmental conservation also need to be taken in account.

In the Eleventh Five-Year Plan, the Chinese government has set a goal of reducing energy consumption per unit of gross domestic product by 20% and a goal of reducing pollutant discharge by 10%, respectively by 2010. In the Eleventh Five-Year Plan for Energy Development, gas supply is set to provide 5.0% of the country's total primary energy by 2010. The Eleventh Five-Year Plan for Management of SO2 instructs that the total SO2 discharge would be reduced to 5.02 million tons per annum and power plants with FGD will be increased 230 GW by 2010. As in the first National Climate Change Plan, the government targeted to reduce total 950 million tons carbon dioxide emissions by 2010.

Needless to say, as a much cleaner energy source, gas-to-power offers significant potential to achieve those polices and goals set by the government. However, to sustain and develop an appropriate level of gas-fired power, certain measures need to be implemented by the government and these are addressed as follows.

5.1 Securing gas fuel by adjusting the structure of gas consumption

The dominant driving force of China's rapid growth of natural gas consumption is gas price. The cheap price of gas currently stimulates a huge demand from fertilizer and some large industrial users. Although the share of gas consumed by the fertilizer industry has dropped, it still accounted for 30.0% of total gas consumption in 2005. As shown in Table 3-6, the prices given to the fertilizer factories are significantly lower than that offered to other customers in Sichuan province. This is the country's largest gas consumption region despite the fact that its economy growth has fallen well behind that of the east coast region. The latest price ratio for city gas, industrial and fertilizer users in Sichuan province is 1:0.95:0.75. Setting a gas price in favor of fertilizer users, that is, farmers, has been one of the government countermeasures against income differences between urban and rural sectors. Driven by the demand from both domestic and international markets, in 2005, China's total fertilizer production reached 48.97

million tons with an annual growth rate of 9.0% from 2000. The annual growth rate of exports of ammonium sulfate reached 77.3%, a figure followed by that for sulfate of potash at 54.4%, ammonium of nitrate at 50.0%, calcium superphosphate at 25.2% and urea at 10.3% (see Table 5-1). Recognizing the gulf in prices for natural gas between domestic and international markets, the fertilizer industry has been consuming enormous amounts of scarce domestic resources at cheapest price to meet the world market demand.

Also, to attract investment and boost their local economies, some local governments have undermined the central government's pricing policy by setting cheaper gas prices for large factory users.

Table 5-1 Export of Fertilizer (2000-2005)

	2000	2001	2002	2003	2004	2005	2005/2000 Annual growth rate
Urea	960.7	1270.2	41.3	2730.3	3942.9	1570.6	10.3%
Ammonium sulfate	15.4	80.1	55.4	109.1	411.8	269.9	77.3%
Ammonium nitrate	29.5	46.8	81.4	119.9	165.8	223.7	50.0%
Calcium superphosphate	273.0	219.2	483.7	513.2	855.0	840.5	25.2%
Muriate of Potash	590.3	330.8	371.3	298.9	100.0	87.2	-31.8%
Sulfate of potash	5.7	14.2	32.3	30.6	44.4	50.0	54.4%

Source: *China's Oil and Chemical Industries 2006*, East and West Trading Press.

Such distortion of the economic growth pattern not only increases trading conflicts between China and foreign countries but also wastes the country's limited natural resources and hence threatens its security of energy supply.

Although the government has a policy to link the domestic gas price with other alternative fuels, it will take least ten years for China to catch up with the international gas price. Under the current tight demand and supply circumstance, the government should not only focus on raising wholesale gas prices but also needs to review the retail prices for fertilizer users. By adjusting the structure of gas consumption by means of reviewing prices for both fertilizer and some large users, some of the inefficient fertilizer and industrial users will eventually exit from the market. This will not only achieve the goal of industrial restructuring, which has been advocated by the government, but also will enable efficient generators to purchase appropriate amounts of fuel to operate their gas-fired plants.

5.2 Introducing a gas-electricity price linking system

Needless to say the critical issue for gas-fired power plants is the price of electricity. The new round of reforms of China's power industry was launched at the end of 2002 and its major purpose was to bring down the wholesale price of electricity. At the time when the new restructuring model was drafted, China was facing a domestic recession subsequent to the Asian financial crisis of 1997 while simultaneously bargaining with the WTO for membership. Given this context, although the power pricing system of the day was not irrational, introducing competition was "two birds with one stone" step for the government. On one hand, it would force the generation sector to reduce their costs, on the other it would break the industry monopoly and demonstrate the government's sincerity in its bid for accession to the WTO. However, nation-wide power shortages that occurred immediately after the reform policy was introduced produced exactly the opposite results to those planned for a number of reasons. One of the major contributing factors was the irrationality of the power pricing system. This paper now analyses this briefly and suggests directions for redressing the problems.

1) *Establishing rationality and transparency for allocating the costs of transmission and distribution*

Although transmission price (including distribution fees) accounted for a minor proportion (30.72%) of the total retail price in 2006, prices for transmission and distribution remain bundled together. Unbundling of transmission and distribution costs is the most difficult task for price reform due to some historical problems and the complexity of the transmission and distribution sectors. Underestimation of transmission and distribution prices hinders the construction of power grids, which has been a long-term bottleneck issue for the industry, whereas overestimation of these same costs will further raise the retail price. Additionally, without a clear breakdown of costs among the three segments, it is difficult to launch a power pooling system and to establish an equal competitive power market for all market participants.

2) *Expanding the range of the fuel adjustment system*

The fuel adjustment system was finally introduced into the power industry in 2005 allowing generators to pass on their costs to the end-users. However, the system takes into account the coal price for power generation only and fails to give consideration to gas fuel prices. Given that the price of gas is expected to increase annually some 8% from now onward, gas-fired generators face an unrealistic operating environment if they cannot pass on increased fuel prices to consumers. Therefore, to mitigate the economic burden on gas-fired generators, a gas-power linkage system also needs to be introduced.

5.3 Establishing a competitive wholesale market that is also favorable to gas-fired power plants

Although current power market reform policy is incompatible with the interests of gas-fired power, with some market design modification it could provide opportunities and benefits for gas-fired electricity generation. The current policy is an initial step towards reform that focuses solely on introducing competition among generators. The next step will address the separation of distribution from transmission and introduce a Third Party System (TPA) but when and how this will happen are not yet clear and related rules have not yet been determined.

As already noted above, three selected regions have introduced different power pooling systems based on each region's power supply and demand conditions. For instance, gas-fired power generators in the east China power exchange are not eligible to participate in the pool, while peak and off-peak products have been introduced into the monthly market in both east China and southern China power exchanges. Recognizing that a gas-fire plant can be started and stopped quickly in response to the load curve, a gas-fired generator would obtain benefits from participating in the power market. A gas-fired generator can sell its generation during the peak period but at a higher price than that determined in the PPA, which does not reflect the flexibility of a gas-fired power even where it is generally operated during the peak period. A well-designed pool market, generally requires ancillary services for a transmission system operator (TSO) to maintain reliability of power supply. Such an ancillary service can either be purchased by generators from an ancillary service market such as the PJM model or be provided by the TSO's imbalancing market as the model in the United Kingdom provides for. Although a pilot program for a power pooling system has been introduced, design and pricing systems for ancillary service have not yet been concretized. Given the same merits of a gas-fired plant as set out above, gas-fired generators could also receive better prices through the ancillary service market or the imbalancing market than prices contracted with grid companies.

By implementation of such a framework for the power pooling system, gas-fired power generators could be compensated via a truly competitive power market. This is in contrast to the current PPA, which hinders full cost recovery for gas-fired power generators.

5.4 Establishing an environmental friendly dispatching system

To achieve the government's environmental protection goals, the power sector, in particular power grid companies, needs to establish a dispatching system, which prioritizes maximum efficiency and minimum pollution. Currently the volume of wholesale power purchased by power grid companies is based on an average level for comparable types of plants in each region and is dispatched without taking account of plant efficiency, energy type and so on. This prevents generators from increasing efficiency and improving their environmental performance. Establishment of an environmentally friendly dispatching system would firstly oblige all generators to submitted a detailed picture of their operation including data on unit capacity, energy type, thermal value, quality of coal fuel, air pollution discharges and quantity of pollutants removed and so on. Based on such a database grid companies could contract with generators in order of maximum efficiency and cleanliness of source until its forecasted demand load was met.

To realize such a dispatching system, a mandatory power purchase policy with a preferential price for gas-fired power comparable to those measures applied for renewable energy power generation is essential. The Renewable Energy Law and its related measures on pricing and cost sharing for renewable energy power generation were brought into force in January 2006. This law mandates power grid companies to purchase all power generated by renewable energy at a price that the government specifies for a 15-year period. It has promoted the development of renewable energy, in particular wind power generation. By the end of 2006, installed capacity of wind power plants increased from 1.26 GW in 2005 to 1.87 GW, an annual growth rate of 48.4% and capacity from this source is expected to be around 30.15 GW by the end of 2020.

The gas-fired power industry is still in its infancy in China and most gas-fired power projects are constructed as appendages to pipeline or LNG projects, therefore, the next logical step is for the government to take gas-fired power as a clean energy and give it the same premium price provided for renewable energy sources. The premium set for renewable energy power generation is RMB 0.25 yuan per kWh and this is added to local uniform wholesale prices for a 15-year period. The same system could be applied as is for gas-fired power and the increased wholesale and retail power prices could be passed on to all end-users. Meeting environmental costs should not only be obligatory for industrial users but also for residential users as well. Supporting and guaranteeing a secure and stable business operation environment for gas-fired power are critically important, particularly where gas is unable to compete equitably against coal and reform of the power industry remains uncertain.

5.5 Implementing a closure policy on small coal-fired power plants in favor of gas-fired power

The government has stipulated that the power sector must reduce SO2 pollution from 111.2 million tons in 2005 to 9.5 million tons by the end of 2010. To do so, approximately 50 GW small (100 MW and below) coal-fired power plants are schedule to be shut down by the end of 2010 and a total 230 GW capacity thermal power plants with FGD is required. To meet this goal some 59.6% of existing power plants and 40.4% of new installed capacity will need to have FGD. As described in Chapter 4.2, the five provinces with heavy dependency on small-fired power plants are, in order, Guangdong, Shandong, Henan, Jiangsu and Zhejiangm, which are also the most polluted provinces in China. Except for Shandong province, pipeline gas or LNG are being utilized in these regions, therefore to control and improve air condition, local governments should encourage and support generators to build a certain level of gas-fired power plants. Gas fired power production is not only a countermeasure for those provinces which dependent on small-scale coal-fired plants or those that are heavily affected by acid rain. Provinces expecting to be connected with gas pipelines in the future should also prepare policies for installing gas-fire power plants. A ban on small-scale coal-fired power plants in China would make gas-fired power a sensible and acceptable alternative from an environmental point of view.

6. Conclusions

Gas-fired power plants have faced several problems ever since they went to operation and both an uncertain future gas supply and the international price of gas have further hindered the development of gas-fired generation in China. Given that gas-fired power is not a competitive energy source compared with coal, which is abundant in China, the government needs to protect and support the development of gas-fired generation when it is still in its infancy as well as to ease uncertainties surrounding the construction of gas-fired generation for the future.

To do so, the government should not only reform the gas industry but also the electricity industry as a whole within the context of its environmental policies. The cheap gas price for fertilizer users needs to be abolished and the government should enforce strict guidance on chemical developments such as gas to methane projects and so on. Domestic gas price needs to be adjusted in line with the international market as quickly as possible to ensure stability and security of gas supply. Meanwhile, under the transitional period of China's electricity market reform, the government should institute a preference for gas-fired power in line with its policies for renewable energy sourced electricity for a least 5-year period. Such policy differentials would not only help existing generators to maintain their current business but would also rebuild market confidence for construction of gas-fired power plants. Additionally, a dispatching system which prioritized clean energy and high efficiency power plants would give generators incentives to both improve the performance of their existing plants and to build more environmental friendly ones. Needless to say, the government needs to give teeth to its environmental regulations by having a comprehensive monitoring system and enforcing stricter penalties where policies are breached.

Prioritizing the development of gas-fired power is consistent with the country's overall energy policy as well as broader economy activities. The recommendations proposed in this paper are not merely to "encourage the growth potential for gas-fired power, but to unlock the development potential of the country's gas market"[7].

[7] *Gas to Power-China*, International Gas Union.

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