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DEVELOPMENT STRATEGIES OF THE CHINESE NATURAL GAS MARKET

BY YI CHEN

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© Shell, 14 January 2007, 'Checking gas detectors at Changbei, China'

DEVELOPMENT STRATEGIES OF THE CHINESE NATURAL GAS MARKET

YI CHEN

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EXECUTIVE SUMMARY

The Chinese natural gas market has entered a stage of rapid growth, having experienced a five-fold demand jump since 2000. The upward surge is expected to continue for the years to come, despite a number of barriers such as the lack of market-based pricing and pipeline infrastructure. Facing the challenges, the government and the gas industry have developed thoughtful strategies to accommodate this rapid growth.

First of all, the Chinese government has maintained a strong hands-on policy during this stage of market development. The government has played an important role in fostering favourable market conditions and has made a serious strategic blueprint to move the industry forward. A series of industrial policies were delivered in 2012: *China Energy Policy 2012*, the *12th Five-Year Plan for the Natural Gas Industry*, the *Natural Gas Usage Guideline 2012* and the *Guideline on Encouraging and Guiding Private Capital in Energy Sector Investment*.

Secondly, the current 'cost-plus'-based pricing regime has been under scrutiny, and a trial pricing reform has been in effect since December 2011. The two southern provinces have initiated an oil-indexation pricing regime. This is a critical step toward establishing a market-based pricing regime, which will provide an incentive to unlock potential unconventional energy sources.

Thirdly, domestic production is key to security of supply, and unconventional supply is expected to play an increasingly important role. In the near-term, conventional production will remain strong. Tight gas and CoalBed Methane (CBM) will be the main driving forces behind unconventional production. Shale gas development is still to start in earnest, but is expected to blossom by the end of this decade, with the participation of a wide range of producers.

Fourthly, China is carrying out large natural gas pipeline import projects with its resource-rich neighbours. On the western frontier, gas has been imported via pipeline from Turkmenistan since 2010 and is estimated to reach a capacity of 55-60 bcm by 2015. On the southwestern border, the Myanmar-China pipeline (12 bcm) is near completion. At the northern frontier, CNPC and Gazprom signed a Memorandum of Understanding (MOU) in March 2013, which could translate into a 38 bcm/year deal from 2018 onwards.

Fifthly, on the Pacific coast, the Liquefied Natural Gas (LNG) import infrastructure, backed by long-term supply and purchase contracts, has grown rapidly to meet the rising demand for clean energy in coastal regions. Since the inception of the Guangdong Dapeng LNG terminal in 2006, seven regasification terminals are now in operation, and six more are under construction. By 2015 China will possess over 60 bcm of annual receiving capacity.

Sixthly, Chinese National Oil Companies (NOCs) are investing aggressively overseas in natural gas assets. One type is investment in unconventional fields in North America to gain experience and technological know-how, such as the deals with Devon and Chesapeake; another is to participate in LNG supply consortia and in new gas fields, such as with the CNPC-ENI deal in Mozambique in early 2013.

Last but not least, while building pipeline infrastructure takes time, a burgeoning mini-LNG industry is emerging in complement to the pipeline grid. The number of Natural Gas Vehicles (NGV), especially LNG-fuelled vehicles, is expected to grow rapidly due to environmental and economic competitiveness.

Looking forward, China will secure growing volumes of long-term supply from abroad, which will expose China to increasing external risks, both politically and financially.

1 INTRODUCTION[1]

The stable economic growth in China is backed by continuous urbanisation and industrialisation, underpinning the country's primary energy demand. This long-lasting growth and an increasing environmental consciousness have diverted the paradigm of energy policy from security of supply to diversification of energy sources and pollution mitigation. As the cleanest form of fossil fuel, natural gas has entered a golden age of rapid growth. Between 2000 and 2012, annual natural gas consumption increased five-fold to reach 147 bcm; domestic production increased four-fold to reach 108 bcm. Despite this tremendous growth, the natural gas industry is still underrepresented in the overall energy mix, constituting a mere 5% of the total composition[2].

FIGURE 1. CHINESE PRIMARY ENERGY SUPPLY 2011

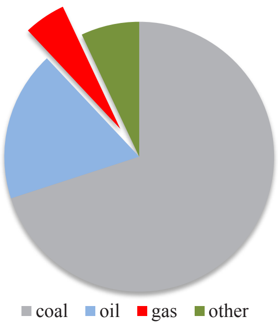
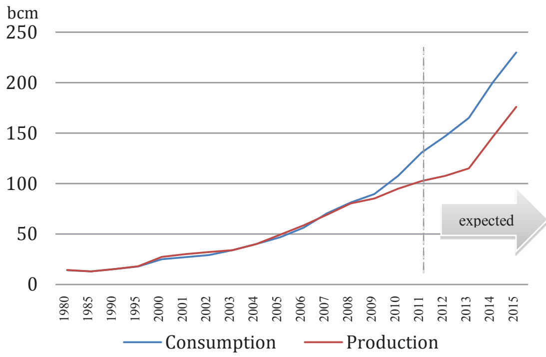


FIGURE 2. CHINESE NATURAL GAS CONSUMPTION & PRODUCTION



SOURCES: CHINA ENERGY STATISTICAL YEAR BOOK 2011, GIIGNL, CNPC, UBS, GOLDMAN SACHS

The government and the industry have an ambitious plan to continue to grow the market for gas despite rising challenges. In the *12th Five-Year Plan for the Natural Gas Industry*, released in 2012 by the National Energy Administration (NEA), the 2015 estimated gas consumption and the domestic production target are set at 230 bcm and 176 bcm, respectively. Conventional and unconventional production are estimated to reach 138.5 bcm and 37.5 bcm, respectively. However, it is highly

1 Yi Chen holds a master degree in international energy from Sciences Po, Paris. With special thanks to the people who have generously provided me with guidance during my internship at the Clingendael International Energy Programme: Coby van der Linde, Lucia van Geuns and Dick de Jong; to my professors at Sciences Po Paris who introduced me to the natural gas market: Giacomo Luciani, Jonathan Stern and Paolo Natali; and to Jonathan Sinton of the International Energy Agency, whose publication on China was my initial inspiration.

2 Zhou Jiping, President of CNPC, *The Rapid Growing World and Chinese Natural Gas Markets*, Conference Presentation on 25th World Gas Conference, Kuala Lumpur, Malaysia, June 7, 2012

unlikely that the 176 bcm goal will be reached. Based on already signed contracts, natural gas import volume through pipeline and as Liquefied Natural Gas (LNG) together will reach 93.5 bcm. With this level of imports, a more modest growth of domestic supply to 136.5 bcm would still allow the country to achieve the target consumption of 230 bcm. If higher levels of domestic production are achieved, the constraints on domestic consumption could be relaxed to exceed the current estimate of 230 bcm.

TABLE 1. PROJECTION OF CHINESE NATURAL GAS DATA FROM 2011 TO 2015

Unit: bcm	2011	2012	2013 e	2015 government
Consumption	130.7	147	165	230
Production	102.5	107.7	115	176 (target)
– Conventional	–	–	–	138.5
– Unconventional	–	–	–	37.5
Import	31.4	42	53	93.5
– Pipeline	15	22	30	–
– LNG	16.4	20	23	–

SOURCES: IEA, CNPC, ENERGY INTELLIGENCE

This near-double target is by no means an easy one, considering that the industry faces major hurdles throughout the entire value chain. Policymakers are very aware of these problems, as six major challenges have been listed in the 12th plan (see Table 2).

TABLE 2. SIX CHALLENGES FACING THE CHINESE NATURAL GAS INDUSTRY

1	Upstream: lack of competition in domestic Exploration and Production (E&P)
2	Transportation: lack of pipeline infrastructure
3	Pricing: current regime does not reflect market fundamentals
4	Technology: lack of technology know-how in unconventional E&P
5	Regulation: lack of legal framework and regulation
6	Security of Supply

SOURCE: 12TH FIVE-YEAR PLAN FOR THE NATURAL GAS INDUSTRY

Upstream competition is very limited, due to strict regulation on exploration licenses in oil and gas drilling. Only a handful of state-owned enterprises are actively engaged in domestic upstream activities, together with a few non-state players operating in the margin. In the midstream, pipeline and storage infrastructure is inadequate to meet the market's demand. Many regions do not have gas access, and the market is usually stuck in an extremely tight position in the winter months due to a lack of storage facilities. By the end of 2010, China had only 40,000 km of gas transmission pipeline, compared to over 100,000 km in Germany and 500,000 km in the US. The working gas in Chinese storages is only 1.7% of the volume of annual consumption, compared to the world average of 12%[3]. Pricing is key to a sustainable and healthy market. However, the current cost-plus price reflects neither the scarcity of the resources nor market fundamentals. The low regulated price carries no incentive for exploration and generates an unsustainable financial loss on imported gas. On the technological front, China has not yet developed sufficient technology to unlock its unconventional potential. China is believed to have the world's largest shale gas reserve, but the US revolution will not be replicated in China anytime soon. Aside from technological insufficiency, there are other difficult issues such as environmental concern and water shortage. In addition, there is a lack of a legal framework. To facilitate a healthy and sustainable growth of the natural gas market, a solid regulatory framework needs to be put into place by the government. Yet there are no appropriate national laws regulating the natural gas industry; nor is there effective regulation regarding pipelines. Finally, the Chinese natural gas market will be increasingly dependent on foreign supply. Thirty-five percent of gas consumed in China will come from overseas by 2015. This poses critical challenges to the security of energy supply.

These challenges are major hurdles to future development, yet they also serve as an agenda for policymakers and industrial executives. In this context, this paper will analyse the development strategies of the Chinese natural gas market in the short to medium term.

3 *Gas Pricing and Regulation, China's Challenges and IEA Experience, Partner Country Series* IEA, 2012, p.27

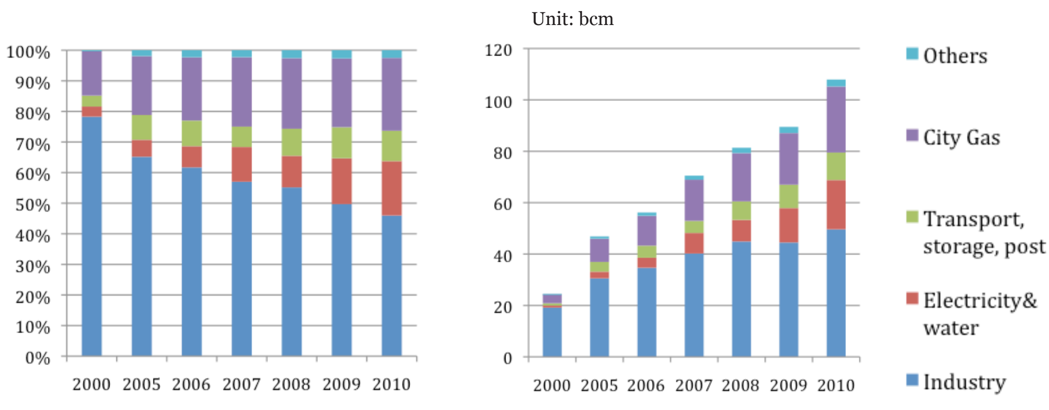
2 ENERGY POLICIES

The government has played an essential role in shaping the fledgling natural gas market. Through strong command-and-control instruments, the government has a large influence on the evolution of the market. Because the government is determined to develop the natural gas market at a rapid pace, a series of industrial policies were put in place in 2012:

- China Energy Policy 2012,
- The *12th Five-Year Plan for the Natural Gas Industry*,
- The *12th Five-Year Plan on Urban Gas*,
- The *12th Five-Year Plan on Shale Gas*,
- The *Natural Gas Usage Guideline 2012*, and
- The *Guideline on Encouraging and Guiding Private Capital in Energy Sector Investment*.

The national consumption pattern is the best example for demonstrating the top-down influence. Industrial and petrochemical sectors are the biggest consumers of natural gas, but its market share has decreased from 78% to 50%. The diversification comes largely from the scaling up of gas-fired power generation and gas utilisation in the residential sector. Residential users are favoured with much lower rates despite the transportation and distribution costs being higher than those for large industrial users.

FIGURE 3. GAS DEMAND BY SECTOR (PERCENTAGE ON LEFT AND TOTAL VOLUME ON RIGHT)



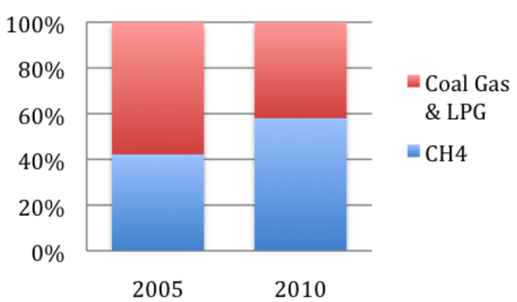
SOURCE: NATIONAL ENERGY STATISTICS YEARBOOK 2011

Environmental concerns and high oil prices underpin the development of gas in the energy mix. In a country in which energy consumption is dominated by coal, natural gas is regarded as a source of clean energy. Strong environmental concern has forced the coal-based economy to search for alternative energy sources. In urban areas, China has been going through a fuel switch transformation from coal to gas, driven by pollution mitigation. In urban China, it is no longer easy to find heating and cooking based on coal. Most recently, coal gas (manufactured coal gas) and Liquefied Petroleum Gas (LPG) have been gradually replaced by natural gas, as shown in Figure 4.

In the industrial and petrochemical sectors, natural gas remains an important feedstock. In the power sector, natural gas is gradually penetrating the once coal-fired-dominated landscape. More gas-fired power plants are being built in China. However, due to government prioritization and the price disadvantage, it is not expected that gas will gain a significant share in the power mix anytime soon.

The second driving force is the high price of oil products. The oil price in China is close to the international market price level, while the price of gas remains low in a highly-regulated environment. This price difference has brought incentives to develop natural gas as an alternative fuel for transportation (see Chapter 8). Natural gas is also competing with fuel oil and LPG in industrial and residential areas (see Section 3.3).

FIGURE 4. URBAN FUEL SWITCH



SOURCE: 12TH FIVE-YEAR PLAN ON URBAN GAS

2.1 GAS USE GUIDELINE 2012

Among the various government policies is the *Natural Gas Guideline*, which provides detailed instruction and direction regarding the utilisation of natural gas in different sectors. At the end of 2012 the National Energy Agency (NEA) published the 2nd edition of the guideline (see Table 3 below).

This document categorised all gas usages and prioritised them in the following groups:

A: prioritised, *B: allowed*, *C: restricted*, and *D: prohibited*.

For example, the first item in the guideline is the usage of natural gas in urban cooking and water heating. It was ranked as 'A' (prioritised) in the 2007 version of Guideline and again as 'A' in 2012. This shows that natural gas has been continuously promoted in urban cooking and water heating. The dashes (–) in Table 3 indicate that specific usages appeared for the first time in the 2012 version, such as No. 8, 'Hydrogen producers with interruptible service contracts'.

The guideline demonstrates the government's intention to intervene in the market to aid healthy growth. It incentivises the use of natural gas in 'sunrise markets' and prevents distortion in other sectors. Here are some highlights:

In the transportation sector, LNG as a transportation fuel appeared for the first time in 2012 and is prioritised. Furthermore, the use of LNG as vessel bunkering fuel also appears as a priority.

Interruptible service is encouraged for industrial users. This refers to contracts in which gas supply is allowed to be interrupted for periods of time. Discount rates are offered for this flexibility.

CBM as a power generation fuel is promoted as 'A'; however, natural gas is not expected to replace coal in the power sector anytime soon. As shown in the table, in the 13 major coal production centres, natural gas is prohibited for base-load electricity production.

In the petrochemical sector, due to the low domestic gas price, there has been an overcapacity of producing certain feedstocks, such as ammonia and methanol; therefore, in the new guideline they are listed as either 'C' or 'D'.

On the energy efficiency front, 'distribution energy projects' appears for the first time in 2012. This category refers to the use of natural gas as a fuel in combining heating and cooling production with electricity generation (70% plus efficiency rate). The country plans to build 1,000 such projects in the coming five years.

In response to insufficient storage capacity and tight supply in the winter, 'Urban storage facility for emergencies and peak-shaving' and 'Small LNG facilities for peak-shaving and storage' are promoted as category 'A' items.

TABLE 3. NATURAL GAS USE GUIDELINE COMPARISON BETWEEN 2007 AND 2012

(A: prioritised, B: allowed, C: restricted, D: prohibited)

Usage	2007	2012
URBAN GAS		
1 Urban cooking and water heating	A	A
2 Urban public facilities (airports, government, cafeterias, elementary schools, hospitals, hotels, restaurants, shopping centres, business buildings, train stations, welfare houses, ports, inter-city bus transit stations)[4]	A	A
3 Natural gas vehicle, especially bi-fuel vehicle and LNG vehicle	A	A
4 Central heating	B	A
5 Air conditioner	B	A
6 Household heating	B	B
INDUSTRY		
7 Construction, machinery, textile and metallurgy companies with interruptible service contracts	B	A
8 Hydrogen producers with interruptible service contracts	—	A
9 Fuel switches from oil or LPG in the construction, machinery, textile and metallurgy sectors	B	B
10 Fuel switches from coal in the construction, machinery, textile and metallurgy sectors with good economic performance	B	B
11 Gas-fuelled new projects in the construction, machinery, textile and metallurgy sectors	—	B
12 Fuel switch for industrial boilers in major urban centres	—	B
POWER		
13 General power generation[5]	B/C	B
14 Base-load electricity production in the 13 major coal production centres (exception: CBM)	D	D
15 CBM electricity generation	—	A
16 Combined heat & power generation	A	A
CHEMICAL		
17 Hydrogen producers except number 8 [6]	B	B
18 Synthetic ammonia plant expansion or new projects using natural gas	C	C
19 Acetylene, Halomethane and other carbon chemistry projects	C	C
20 New plants using natural gas in producing nitrogen-rich fertiliser [7]	B/C	C
21 Methanol production	D	D
22 Fuel conversion from coal in methanol production	D	D
OTHER		
23 Combined Heat and Power projects (70% efficiency)	—	A
24 Natural gas-fuelled vessels, especially LNG (including bi-fuel)	—	A
25 Urban storage facilities for emergencies and peak-shaving	—	A
26 Small LNG facilities for peak-shaving and storage	—	B

SOURCES: NATURAL GAS GUIDELINE 2012, NATURAL GAS GUIDELINE 2007

4 The 2012 paper elaborated on the specific kind of public facilities: hospitals, train stations, welfare houses, ports and inter-city bus transit stations.

5 In 2007, there were two rankings: (1) category B: 'in important heavy-load regions with abundant gas supply, establish peak-shaving projects'; (2) category C: 'for non-important heavy-load regions'.

6 In 2007, the narrative was 'for low gas-consumption projects with good economic performance'.

7 In 2007, the narrative for B was: 'producing nitrogen-rich fertiliser with difficult to transport and extra-supplied gas'; all others were C.

3 DOMESTIC PRICING REGIME AND REFORM

China's gas pricing is a cost-plus regime that is regulated throughout the entire value chain. It has undergone some transformation as the economy evolves towards a market-based economy. Nevertheless, it is essentially a fixed-price model, and a market-based pricing mechanism has yet to be established. In response, since December 2011 a trial reform has been undertaken in two southern provinces, which overhauls the old pricing formation and moves toward an oil-indexation mechanism. The ultimate goal is to liberalise the wellhead price and develop a market-based pricing regime.

3.1 CURRENT PRICING REGIME

Cost-plus pricing is a very intuitive pricing model. In accordance with the value chain, the pricing formation flows from the price set by the government for the upstream producer to the midstream pipeline operator and then to the end user. Figure 5 shows an illustrative model.

FIGURE 5. A SIMPLE MODEL OF COST-PLUS PRICING FORMATION

For example, natural gas transported through the West-East Pipeline (Phase I) in 2008 from Xinjiang to Shanghai was priced as shown in Table 4 below. The city gate price is equal to the wellhead price plus the pipeline tariff.

TABLE 4. WEST-EAST PIPELINE (PHASE I) GAS 2008, DESTINATION: SHANGHAI
UNIT: (RMB/THOUSAND CUBIC METER)

Sector	Wellhead Price		Pipeline Tariff		City Gate Price
Industrial	960	+	800	=	1760

SOURCE: IEA 2009

Based on this simple model, a more realistic one is depicted in Figure 6. In the pricing regime prevalent today, there are regulations on all three segments of the value chain. For gas production and processing, the wellhead price is calculated based on the cost-plus formula below. Note that a price range (±10%) clause has been introduced to bring flexibility to the negotiation between producers and end users.

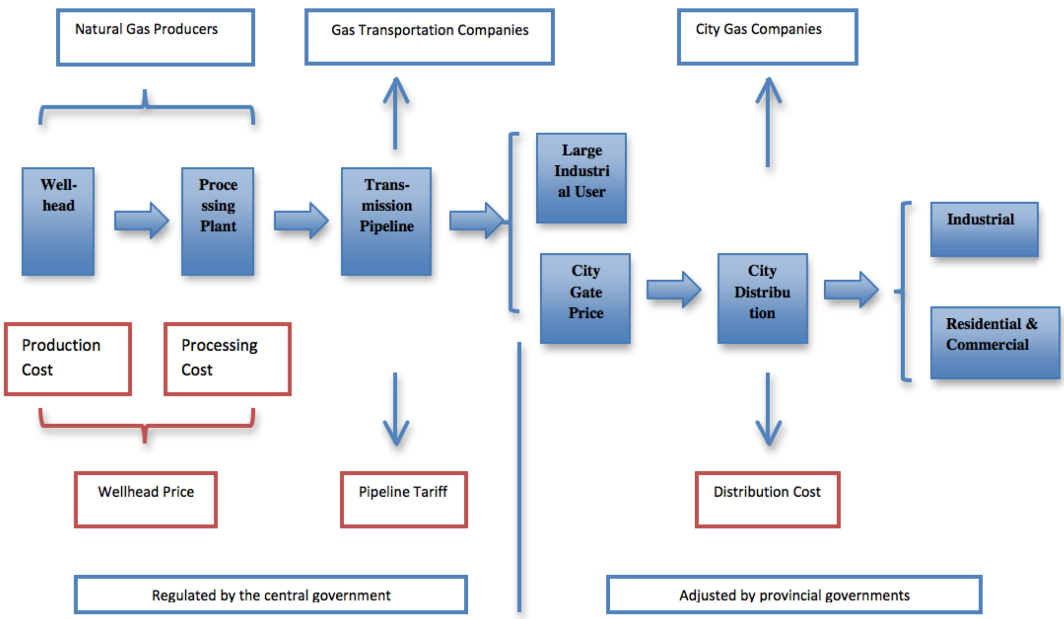
Wellhead price = production cost + processing cost + financial cost + 12% International Rate of Return (IRR)[8]

Similar to this concept, the transportation cost is also regulated in a cost-plus manner. Transportation cost is a function of distance and the pipeline cost. The pipeline cost formula is shown below:

Pipeline tariff = construction cost + operational cost + financial cost + 12% IRR[9]

While wellhead price and pipeline tariff are regulated at the national level, city gate prices are adjusted by provincial governments based on regional economic disparity and local distribution costs.

FIGURE 6. CHINESE GAS PRICING REGIME[10]



SOURCE: 'CHINESE NATURAL GAS PRICING DILEMMA - ESSAY ON CHINESE GAS PRICING REFORM'[11]

8 Nobuyuki Higashi, *Natural Gas in China Market: Evolution and strategy*, IEA, June 2009
9 Ibid.
10 Due to simplicity and low storage facility, the storge factor is not included.
11 The original Chinese text is '中国天然气价格困局—天然气价格改革思考之一'.

It is important to note that the system is not entirely 'cost-plus': both wellhead price and final user prices vary, based on the sector to which the gas is sourced. It means that (1) gas producers receive different rates depending on the sector to which the gas is shipped; (2) an industrial end user faces a different rate than does the residential end user. Table 5 shows that if gas goes to the fertiliser sector, the gas producer will receive 790 RMB, whereas if the gas goes to large industrial users, the gas producer will receive 1190 RMB per thousand cubic meter.

TABLE 5. WEST-EAST PIPELINE (PHASE I) 2010

Destination of the gas	Wellhead price, $/MMBtu[12]
Fertiliser	3.45
Large Industrial User	5.2
City Gas (industry)	5.2
City Gas (non-industry)	3.45

SOURCE: NDRC 2010

Different types of end users pay different prices as well. Table 6 illustrates that in Beijing in 2011, residential users paid an average of $9.01/MMBtu, which is substantially lower than the price paid by consumers in the public service, industrial and transport sectors. However, this is not economically logical, since large industrial users have direct access to the transmission pipeline. It means that the cost of shipping gas to industrial users is lower than the cost for residential use, which includes the extra distribution cost. Why so? From the standpoint of equity, the government may think it is justified in keeping the cost of living low for residential users. Also, keeping the residential price low will maintain a stable Consumer Purchase Index (CPI), which is a key indicator under public scrutiny.

ABLE 6. END-USER PRICE IN BEIJING IN 2011

$/MMBtu	Residential	Public services	Industry	Transport
Beijing	9.01	12.48	12.48	20.79

SOURCE: IEA

12 1 k cm = 36.7 MMBtu, Exchange rate: $6.24430

3.2 CHALLENGES TO THE CURRENT PRICING REGIME

There are numerous challenges facing the current pricing regime. Firstly, the cost-plus model functions well in a simple network. However, with increasing pipeline interconnections, it is no longer easy to identify different sources of natural gas within one pipeline. Secondly, the cost-plus regime does not provide the fundamental price signal that a market economy requires. A clear price signal is essential to reflect the market value of a natural resource, to indicate the market trend and to guide the investment decisions. The low domestic price disincentivises upstream companies from investing in the E&P, thus hindering the development of conventional and unconventional reserves. Also, the low price distorts the market, which has induced the overproduction of petrochemical products such as ethanol and methanol in previous years. Furthermore, the price gap between cheap domestic and expensive imported gas has led to significant financial losses of NOCs. Another issue is the lack of an upstream-downstream price adjustment mechanism. When there is a price increase at the wellhead, it takes at least a few months to reflect the price increase on the end-user side. This means that city gas companies have to bear the policy-induced financial burden. In addition, in the pricing design, there is no consideration for seasonality. The seasonal behaviour of natural gas consumption is highly determinant: the peak demand in Beijing is ten times higher than the trough level.

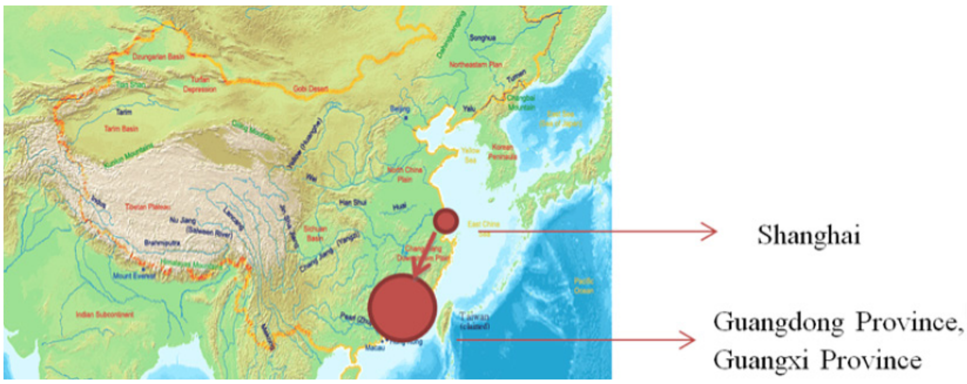
In the wake of these challenges, the government has taken serious steps to improve the pricing scheme. In the past decade, the pricing code has been simplified and the wellhead price has been increased several times to bring incentives to the gas producer and rebalance the market. The real game changer is a statement made by the National Development and Reform Commission (NDRC) in December 2011, which started a trial pricing reform based on oil indexation in Guangdong and Guangxi provinces. The new pricing regime is expected to be extended nationwide in the next few years. It will not only narrow the gap between domestic and international gas prices but, more importantly, it will be a critical step toward a market-oriented natural gas market.

3.3 NEW PRICING REGIME

The pricing regime will use the concept of oil indexation to determine the gas price in Guangdong and Guangxi provinces. First of all, the Shanghai city gate price has been chosen as the benchmark, due to its interconnectivity of multiple sources (Xinjiang gas, Turkmen gas, Sichuan gas, East China Sea gas, and LNG imports). The Shanghai price is proportionally linked to the imported fuel oil price and imported LPG (Liquefied Petroleum Gas) price in any given time period. Fuel oil is widely used in the industrial sector in China and LPG is commonly used in the residential sector.

By linking the price of domestic natural gas with the international price of its competing fuel, the oil-indexed price formula will reflect international market fundamentals. Also, with the discount rate K=0.9, natural gas will gain an advantage in competing against fuel oil.

FIGURE 6. TRIAL PRICING FORMATION: NETBACK FROM SHANGHAI HUB PRICE TO CITY GATE PRICE



SOURCE: AUTHOR

Step 1. $\mathrm{P\ (Shanghai)} = K \times \left(\alpha \times Pfuel\ oil \times \frac{Hgas}{H\ fuel\ oil} + \beta \times PLPG \times \frac{Hgas}{HLPG}\right) \times (1+t)$[13]

Notes:
P (Shanghai): Shanghai benchmark natural gas price
K: discount rate = 0.9, to promote the use of natural gas
α: 60% weight on fuel oil
β: 40% weight on LPG
Pfuel oil: imported price of fuel oil during the period in RMB/kg
PLPG: imported price of LPG during the period in RMB/kg
Hgas: heat content of natural gas
Hfuel oil: heat content of fuel oil
HLPG: heat content of LPG
t: Value-Added Tax of 13%

Secondly, with the Shanghai benchmark price, the city gas price in Guangdong and Guangxi will be calculated through the formula as such:

13 *Notice of Pricing Formation Trial Reform in Guangdong and Guangxin*, National Development and Reform Commission, December 2011

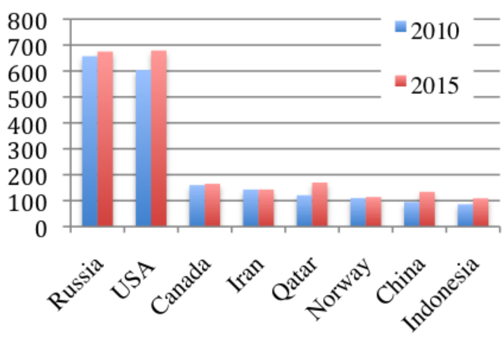
Step 2. City Gas Price (Guangdong) = P (Shanghai) + P (transportation from Shanghai to Guangdong) + Provincial adjustment factor

It is expected that this formula will gradually be extended to the whole nation. The goal is to establish a sound market-based pricing mechanism that reflects demand and supply fundamentals. Eventually the wellhead price will no longer be subject to the government-administered price but will be set on a market basis.

4 DOMESTIC SUPPLY

Although China realises that it is no longer possible to fuel its unprecedented economic growth by its own energy production, domestic supply remains at the heart of security of supply. China is currently the world's 7th largest producer of natural gas and will be the 6th by 2015. China began importing natural gas in 2006 and has increased the volume drastically since then. In 2011, domestic production supplied 78% of total consumption. To keep the external dependence ratio at a stable level, the government has set the domestic production goal of 176 bcm by 2015 vis-à-vis the consumption of 230 bcm. In the 12th Plan, China plans to develop four major production centres (Table 7), each of which will have over 20 bcm in annual production capacity. This is an ambitious plan, considering it requires doubling the production level of 2010 from these areas.

FIGURE 7. MAJOR GAS PRODUCERS, 2010-2015 (UNIT: BCM)



SOURCE: IEA WEO 2012

TABLE 7. FOUR GAS PRODUCTION CENTRES IN CHINA

Unit: bcm	New Capacity	2015 production target
Ordos Basin	26.1	39
Sichuan Basin	19.5	41
Talimu Basin	14.7	32
South China Sea	10	20
By 2015	70.3	132

SOURCE: 12TH PLAN

The remaining 44 bcm of production for 2015 will come from other, smaller fields outside the four production areas.

4.1 UNCONVENTIONAL GAS

In the long run the conventional fields are aging and China will not be able to sustain its domestic production without tapping its potentially massive yet complex unconventional reserves. Beyond the popular perception of a large shale gas potential, China also has large reserves of CoalBed Methane and tight gas. According to CNPC, China's technically recoverable reserves of tight gas and shale gas are 12 tcm and 25 tcm, respectively, which together is more than the conventional reserves potential (32 tcm). Tight gas production is already a mature technology, which reached the threshold of 20 bcm in 2011. China produced 10 bcm of CoalBed Methane in 2011 and its technology is basically mature[14]. In the 12th Plan, China is expected to produce 37.5 bcm of unconventional gas, 15-18 bcm of this being coal gas, 16 bcm CBM and 6.5 bcm shale gas[15].

TABLE 8. UNCONVENTIONAL GAS IN CHINA

	2011 production	Technically recoverable reserves
Tight gas	20 bcm[16]	12 tcm
CBM	10 bcm capacity	10.9 tcm
Shale	Not commercial yet	25.1 tcm
Conventional	-	32 tcm

SOURCE: CNPC

The Chinese shale gas has not yet started commercial production. The US shale gas revolution is not expected to be replicated in China anytime soon. Since 2011, there have been pilot development tests, with a daily output of 200,000 cm. Yet the complex and environmentally-sensitive geology, the dense population in the area of the reserves and the lack of water are hurdles to Chinese shale gas exploration. As Sinopec CEO Fu stated, 'We are not focusing as much on shale gas because it will cost a lot more than in the US'[17]. Nevertheless, China does have an ambitious plan to unlock the massive domestic unconventional potential. In the 12th Plan, shale gas

14 Zhou Jiping, IGU, 2012
15 12th Plan.
16 Please note that tight gas is not regarded as unconventional gas in the Chinese statistical system.
17 Fu Chengyu, interview by *Energy Intelligence,* 2012

production is targeted at 6.5 bcm by 2015 and 60-100 bcm by 2020. Policymakers and industry leaders have taken major steps to prepare for the boom of Chinese shale gas exploration.

First and foremost, the government allows a large range of E&P companies to enter into the shale gas business. The US shale gas success has shown that a diverse group of players in upstream exploration is key to a dynamic exploration landscape. Traditionally, one of the fundamental problems has been the lack of competition in E&P. During the first round of shale gas exploration rights tendering, organised by the Ministry of Land and Resources in 2011, only four domestic oil companies (CNPC, Sinopec, CNOOC and Yanchan Oil) and two CBM companies (Zhonglian and Henan) were invited. To bring competitiveness to this sector, shale gas has been listed as a special category of natural resources, and thus doors have been opened to alternative investors. In the 2nd round of bidding in 2012, nineteen companies won the bids with no participation of oil majors. Major coal and electricity producers such as Huadian are pioneering in shale gas. A strong involvement of financial investors is present, such as by the Chinese Sovereign Wealth Fund (CIC) and many provincial investment arms. Also, two non-state-owned enterprises were offered exploration rights, which was a sign of growing private interests in the once state-dominated sector.

Secondly, Chinese NOCs paired up with foreign partners to jointly develop the shale gas projects. On the intergovernmental level, China and the US signed '*The Memorandum of Cooperation on Shale Gas between the U.S. Department of State and China's National Energy Administration*' in 2009. Sinopec and PetroChina have partnered with many oil majors, such as Chevron, TOTAL, ExxonMobil; and service companies such as Schlumberger, Halliburton and Baker Huges. Recently ConocoPhilips signed a Joint Study Agreement (JSA) with PetroChina to examine the prospectivity of the 500,000-acre Neijiang-Dazu Block in the Sichuan Basin. The JSA is a signal for further co-operation, as in the case of the CNPC–Royal Dutch Shell deal. Shell is the largest foreign participant in Chinese unconventional gas. The 2009 JSA between CNPC and Shell had translated into a Production Sharing Agreement (PSA) for shale gas exploration, development and production in the Fushun-Yongchuan block in the Sichuan Basin[18]. The project remains in the early stages of development, but Shell plans to invest at least one billion US dollars annually in Chinese shale gas[19].

18 Royal Dutch Shell

19 *Shell to Start Chinese Shale Gas Project Development From 2014, Bloomberg*, Nov.15, 2012

Historically, Chinese NOCs have developed a win-win strategy with IOCs as follows: a Chinese NOC would build a partnership with a foreign IOC for an overseas project in exchange for a domestic shale gas project. This was demonstrated by CNPC's partnership with Shell, ENI and ConocoPhilips. Shell was the pioneer in Chinese shale gas. In return, Shell co-operated with PetroChina on the Groundbirch shale play in British Columbia, and PetroChina became a minority equity investor in 2012. Similarly, ConocoPhilips and PetroChina now have deals in both Australia and the Sichuan Basin in China. In early 2013, ENI and CNPC struck a large deal on the Eastern African gas frontier. ENI is the biggest gas producer in Africa and holds half the stake in Mozambique's Block 4 license. ENI sold 20 percent of this stake in exchange for 4.2 billion dollars. Meanwhile, CNPC and ENI signed a shale gas co-operation project in the Rongchang block of the Sichuan Basin[20].

20 Financial Times

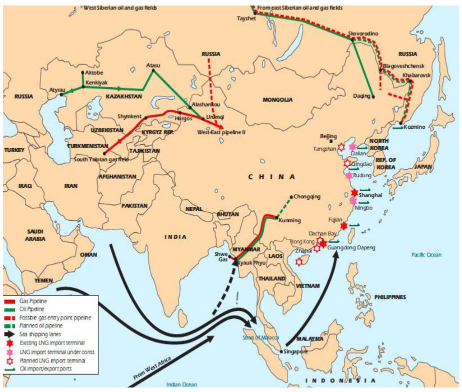
5 IMPORTS BY PIPELINE

In East Asia, China is the only country that imports gas both through LNG and pipeline. The proximity to gas-rich neighbouring countries and the diversification of risk away from dependence on the Strait of Malacca are the underlying driving forces behind pipeline projects. There are three pipeline corridors: from Central Asia, from Myanmar and from Russia. The Central Asian pipeline provided 20 bcm in 2012 and is expected to reach 60 bcm capacity by 2015. The Myanmar pipeline will be completed in 2013. The long-negotiated Russian project moved forward during President Xi's visit to Moscow in March 2013.

TABLE 9. CHINESE IMPORT PIPELINE[21]

From	Stage	Capacity
Central Asia	Phase I completed (domestic project), Phase II completed, Phase III under construction	12 -17 bcm 30 bcm by 2012 30 bcm by 2015
Myanmar	Under construction	12 bcm, by 2013
Russia	Ongoing negotiation	West Route: 38 bcm East Route: 30 bcm (under negotiation)

FIGURE 8. CHINESE ENERGY CORRIDOR



SOURCE: IEA 2012

21 IEA 2012

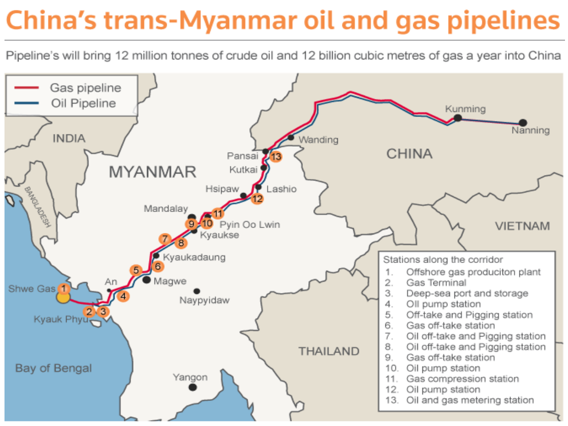
5.1 WEST-EAST PIPELINE: GRAND PROJECT

It is important to understand Turkmen gas imports in the context of a grand Chinese infrastructure project called the West-East Pipeline (WEP). China's main energy consumption is in its eastern and southern coastal regions, which lie 3,000 kilometres from the gas-rich province of Xinjiang. WEP Phase I was actually a domestic project that linked the Talim Basin (in Xinjiang Province) to Shanghai with 12 bcm of annual capacity, which was completed in 2004. The Phase II of WEP taps into the reserves of China's Central Asian neighbours. In January 2009, CNPC signed the contract with Turkmenistan, which will deliver 30 bcm annually for 30 years: 17 bcm from commercial purchases and 13 bcm from CNPC's project in Turkmenistan. The pipeline links to China's third largest city, Guangzhou, on the southern coast. Phase III of WEP, expected to be completed in 2015, will boost import capacity by up to 30 bcm from Central Asia.[22] All together, the West-East Pipeline will have over 72 bcm capacity upon completion of phase III.

FIGURE 9. WEST-EAST PIPELINE

SOURCE: WWW.OILSEEDCROPS.ORG

FIGURE 10. CHINA-MYANMAR PIPELINE



SOURCE: REUTERS

5.2 CHINA-MYANMAR PIPELINE: NEAR COMPLETION

A second pipeline import project is to link Myanmar's offshore natural gas to the southwestern province of Yunnan. Although Myanmar is experiencing civil instability, the pipeline project is expected to be realised by the end of 2013. The project is over 2,000 km long, including 793 km of pipeline in Myanmar and 1,727 km in China. The full capacity will ultimately reach 12 bcm annually. The pricing formula is based on an oil-indexation term with a slope of 7.9[23].

22 *West-East Pipeline phase III starts Oct.17, 2013,* www.people.com,

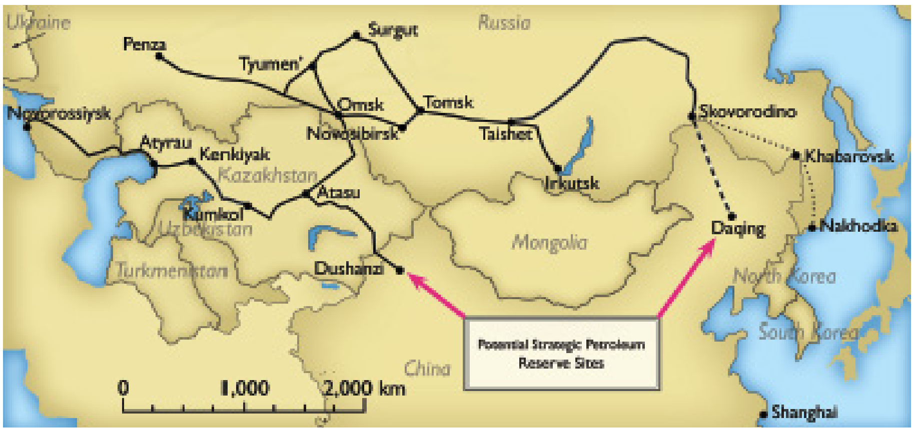
23 Stern, p.325, 2012, here the 'slope' refers to coefficient a in the oil indexation formula: *P(gas) = a*P(oil)+b*

As a side note, the gas import is complemented by an oil transit pipeline (440,000 b/d). The oil pipeline is considered as an alternative to the Strait of Malacca as a transit route for bringing Middle Eastern/African oil to China, with an oil wharf built on the Myanmar coast with storage facilities. China will pay a transit fee of one dollar per barrel to the Myanmar government. Meanwhile, a new refinery and petrochemical complex are under construction in Yunnan province. The oil and gas from and through Myanmar will be a significant source of energy for the southwestern region of China.

5.3 CHINA-RUSSIA PIPELINE: ON THE HORIZON

China and Russia have been discussing for years the option of building gas pipelines through the West and East Routes. Despite tremendous interest on both sides, no constructive steps have been taken due to disagreement over pricing terms. However, President Xi's visit to Russia in March 2013 has moved the deal forward. President Xi chose Russia as his first foreign visit destination, and the political implication of this are tremendous. During the visit, Gazprom and CNPC signed a Memorandum of Understanding (MOU) for the Eastern Route project. If it were to be realised, the deal would be a 30-year contract with 38 bcm annual sales volume starting in 2018; it could be further upgraded to 60 bcm. The West Route is still under price term negotiation.

FIGURE 11. POTENTIAL CHINA-RUSSIA PIPELINE



SOURCE: 'CHINA'S OIL SECURITY PIPE DREAM', ANDREW S. ERICKSON AND GABRIEL B. COLLINS

The optimism of the China-Russia energy relationship comes from the extensive and deep energy co-operation between the two neighbouring countries. China has already built an oil pipeline from Siberia to refineries in northeastern China with 600,000 b/d capacity through an oil-for-loan deal; Rosneft will sign a second deal with CNPC in order to get the critical capital for its mammoth TNK-BP acquisition and domestic refinery modernisation. In addition to oil, China and Russia are also co-operating on nuclear, hydro and electricity frontiers.

In sum, despite regional tensions, China will continue to increase its pipeline imports and strengthen regional co-operation through frameworks such as the Shanghai Cooperation Organization. It is also highly likely that China and Russia will strike a gas deal, due to the fundamentals of soaring Chinese demand and Russia's desire to capture Asian market.

6 LNG IMPORTS

In addition to the three pipelines, the eastern coast's regasification terminals serve as another strategic corridor for international natural gas supply. China has been importing LNG since 2006, and the volume has reached approximately 20 bcm. In 2012, China surpassed the UK and Spain to become the third largest LNG importer after Japan and Korea.

Infrastructure build-up is essential to the increasing demand for LNG imports. Since the inception of Shenzhen Dapeng LNG terminal, five additional regasification terminals have begun operation, with a current total receiving capacity of 30.9 bcm. In the meantime, seven new terminals and one Phase II expansion project are under construction, having a total capacity of 31.2 bcm. By 2015, this will add up to a total receiving capacity up to 62.1 bcm (see Table 10).

TABLE 10. LNG RECEIVING TERMINALS IN OPERATION (LEFT) AND UNDER CONSTRUCTION (RIGHT)

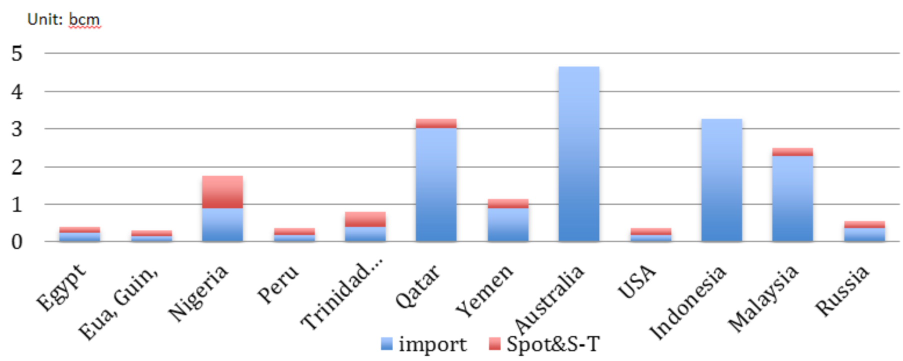
Project	Year in operation	Capacity (bcm/y)
Guangdong Dapeng	2006	5.2
Fujian Putian	2009	3.6
Shanghai	2010	4.1
Jiangsu Rudong	2011	4.9
Zhejiang Dalian	2011	4.2
Zhejiang Ningbo	2012	4.2
Guangdong Dongguan	2013	4.7
total		**30.9**

Project	Year in operation	Capacity (bcm/y)
Guangdong Zhuhai	2013	4.9
Hebei Caofeidian	2013	4.8
Shandong Qingdao	2014	4.1
Hainan Yangpu	2014	4.2
Shenzhen	2015	5.6
Guangxi Beihai	2015	4.2
Fujian Putian *Phase II*	—	3.4
total		**31.2**

SOURCES: IEA, UBS, JOVO, XINHUA, CHINA5E AND SINOPEC

In 2011, China imported 16.6 bcm of LNG, most of which was based on long-term sales contracts and a small proportion coming from short-term and spot purchases. Australia, Qatar and Indonesia are the three main suppliers with long-term contracts. Spot market purchases from the Atlantic Basin added up to 2.83 bcm from various producing regions as far away as Peru and Equatorial Guinea (see Figure 12).

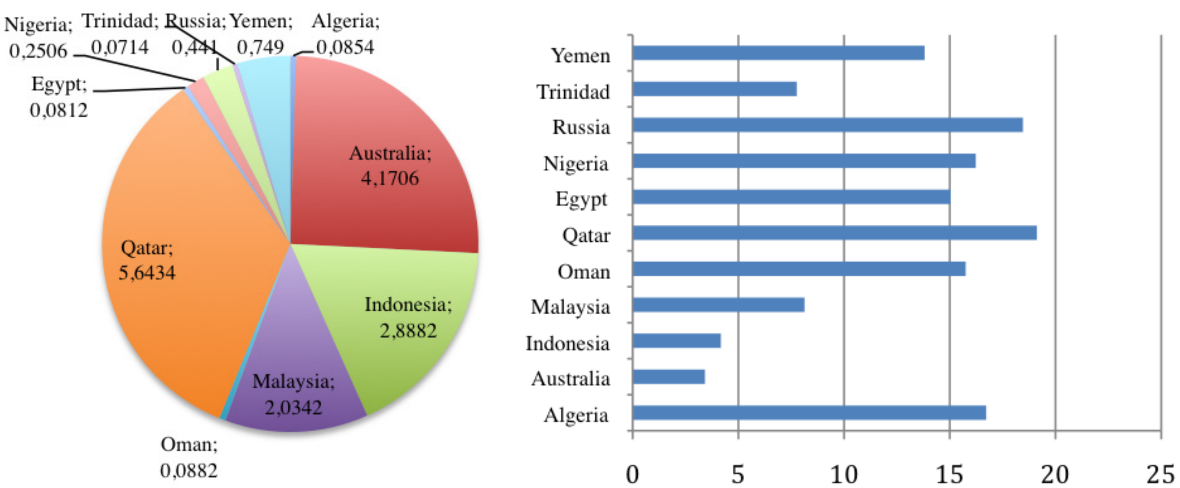
FIGURE 12. 2011 LNG RECEIVED BY IMPORTING COUNTRIES



SOURCE: GIIGNL

LNG imports continued to grow rapidly in 2012 to a record high of 19.5 bcm. The data from the first 10 months of 2012 indicate that the supply from Qatar has surpassed that from Australia. Australia signed the initial sale and purchase deal with China in the early 2000s, with a very attractive price of below $5/MMBtu. However, the days of cheap LNG have passed as the expensive Qatari long-term contracts push up the price. Spot market and short-term purchases are all expensive cargoes.

FIGURE 13. 2012 JANUARY - OCTOBER IMPORTS BY ORIGIN, BY VOLUME (LEFT) AND PRICE (RIGHT)



Unit: bcm

Unit: $MMBtu

SOURCES: GIIGNL, UBS

6.1 LONG-TERM CONTRACTS

Unlike the Atlantic Basin, Asian LNG deals are dominated by long-term contracts. The underlying reasons are based on considerations of security of supply for the buyers and security of demand for the producers. Before the construction of LNG plants and receiving terminals, the buyer and seller usually agree on a long-term purchase and sale contract, as a way of managing supply risks and financing their investments. Table 11 below summarises all the existing long-term contracts that Chinese buyers have signed for LNG projects. It indicates an upward price surge: all the new cargoes coming on board from 2015 onwards will have the price level of approximately $15/MMBtu or more (given an oil price of $100/bbl). Also, Australia will demonstrate its increasing presence in the Asian LNG market as the new number one global LNG producer. (see Chapter 7 on Chinese-Australian LNG co-operation.)

TABLE 11. CHINESE LONG-TERM CONTRACTS[24]

Seller	Buyer	Import	Volume, bcm	First arrival	Length	Oil-indexed price formation
Australia NWS Consortium	CNOOC	Dapeng	4.55	May 2006	25	Slope of 5.25%
Indonesia Tanguhh LNG	CNOOC	Fujian	3.64	July 2009	25	5.25%
Malaysia LNG TIGA	CNOOC	Shanghai	4.2	October 2010	25	7%
QatarGas II	CNOOC	Zhejiang	2.8	2009	25	15-16%
TOTAL Portfolio	CNOOC	China	1	2010	15	15-16%
QatarGas IV	CNPC	Jiangsu	4.2	2011	25	
QatarGas III	CNOOC	Ningbo	4.2	2013	n/a	MOU
GDF-Suez	CNOOC	Fujian/ Shenzhen	3.6/ four years	2013	4	
Australia-Queensland /BG	CNOOC	Fujian/Zhuhai	5	2014	20	14-15%
BG portfolio	CNOOC	n/a	7	2015	20	
Australia-Gorgon/Exxon	CNPC	Shenzhen	3.15	2014	20	14-15%
PNG LNG/ Exxon	Sinopec	Qingdao	2.8	2014	20	14-15%
Australia-Gordon/Shell	CNPC	Jiangsu/ Dalian	2.8	2015	20	14-15%
AP LNG/ Conoco/Origin	CNPC	Beihai	10.6	2015	20	14-15%
Australia-Icon	Sinopec	Guangdong, Shantou	2.8	2016	20	

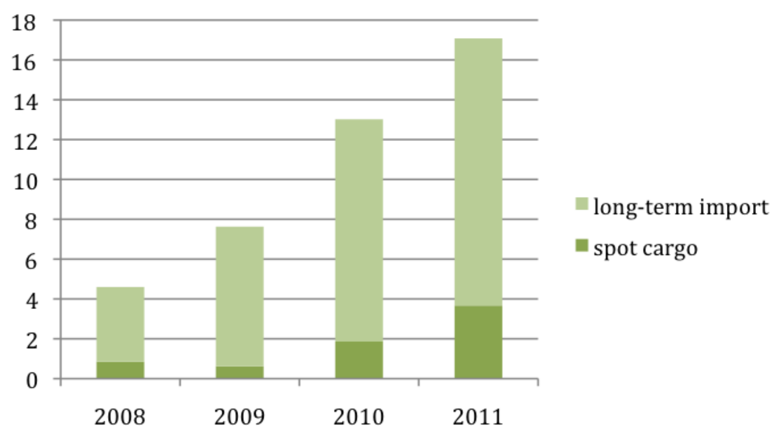
SOURCES: IEA, JONATHAN STERN, OIES, GIIGNL, UBS, WALL STREET JOURNAL, AND THE AUTHOR

24 Northwest Shelf and Tanguh LNG are subject to price revisions every four years, and therefore the price could rise in the future (Stern 2012 P.336).

6.2 SPOT MARKET[25]

Though long-term contracts remain dominant in the Pacific LNG market, the share of spot market and short-term purchases in the global LNG supply rose rapidly in 2010 and 2011. The volume reached 83 bcm, which is over 25 percent of the internationally-traded LNG market[26]. The Fukushima accident and the collapse of the American LNG import market contributed to this shift. The destination clause, which was standard in long-term contacts before 2006, was eliminated or at least became flexible in the newly-signed contracts. In this context, the Chinese traders are also utilising the spot market to complement long-term purchases.

FIGURE 14. CHINESE SPOT MARKET PURCHASES OF LNG (BCM)



SOURCE: GIIGNL, UBS

One of the major reasons for spot purchases is to balance seasonal demand. China, like other Asian buyers, lacks sufficient storage facilities. As mentioned in the Introduction, the current Chinese working gas storage is 1.7% of consumption volumes, compared to the world average of 12%. In the demand centre of coastal China, there are hardly any natural storage facilities for gas (salt caverns, depleted reservoirs). Yet demand patterns for natural gas are highly volatile. Beijing's peak consumption levels are 10 times that of its trough levels. It is therefore well-known that the Chinese as well as other Asian buyers scramble for a limited number of LNG cargoes during the winter months in order to meet high demand. The Asian spot price in a cold winter could easily reach oil parity.

25 UBS China Natural Gas Monthly, July 2012

26 World Energy Outlook 2012

Domestically, regulated price and an integrated value chain still form the basis of the dominant price formation. Although the market structure is far from a suitable environment to foster hub trading, both the government and gas majors have shown an interest in developing a market-oriented mechanism in gas trading. The Shang Petroleum Exchange, which was launched in 2006 to trade oil products, started an LNG trading programme in 2010. Though the volume is small and the purpose remains seasonal balance and peak-shaving, it opens the door for future development.

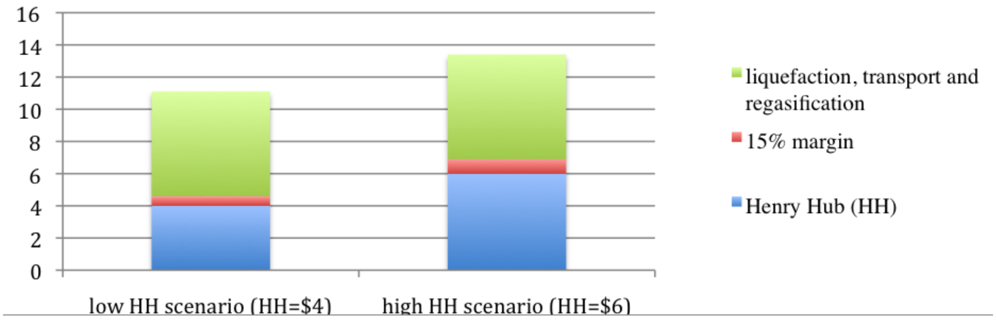
6.3 PRICE GAP

The price of imported LNG is expected to rise soon to average East Asian levels. In the meantime, the domestic gas price remains low. The price of imported Turkmen gas is higher than the average residential rate in major Chinese cities. The price gap is not sustainable for the import company. For example, in 2012 the Turkmen gas at the Chinese border is priced at $8.04/MMBtu, and the pipeline tariff to Guangdong is $4.38/MMBtu; therefore the city gate price should be $12.42/MMBtu. However, the Guangdong city gate price is fixed at $10.9/MMBtu. According to this calculation, the company loses $0.06 for every cubic metre it imports from Turkmenistan. China imported approximately 20 bcm in 2012, which means CNPC potentially lost $1.2 billion on importing Turkmen gas, not to mention the more expensive Qatari LNG cargoes[27].

Facing the increasing price gap, the gas industry is taking decisive action to mitigate the problem. Firstly, the Chinese import company tried to negotiate the pricing formulas with tools such as the S curve in order to protect against the high oil price scenario. Secondly, the Chinese are looking for cheaper import sources. The North American gas glut has attracted tremendous attention from Asian buyers. The $3/MMBtu gas price on one side of the Pacific Ocean versus over $15/MMBtu on the other side seems to be the ideal arbitrage opportunity. Yet the geographical distance and the nature of LNG engineering make the perspective less appealing. A simple calculation (see Figure 14 below) shows that the minimum price tag for a North American LNG cargo shipment to Asia will be over $11/MMBtu.

27 *Natural gas pricing reform receives initial recognition,* china5e.com, Aug. 1, 2012

FIGURE 15. PRICE SCENARIOS OF NORTH AMERICAN LNG SHIPMENTS TO ASIA



SOURCE: SHELL, ENERGY INTELLIGENCE

LNG from the US will have to come from its East Coast with relatively low processing, but high transport costs. Henry Hub is in a contango market with higher price expectations. With strict federal regulation on gas export permitting, the perspective of a significant volume of export from the US to China in the near term is doubtful. However, additional Canadian LNG exports are also being pursued. Together, North American LNG exports will affect the competitive scene in the Asia Pacific market.

As another solution to mitigate the price gap, Chinese gas import companies are investing in LNG upstream consortia. As an equity investor, this will not only help secure long-term LNG supply, but also make a return on the upstream of the value chain to make up for the import loss (see a description of Chinese overseas investment in Chapter 7).

Finally, raising domestic end-user price could be the ultimate solution to the price gap. As discussed in Chapter 3, an oil-indexed pricing regime has been introduced and the end-user price is expected to rise substantially in the years to come. In the near term it may be difficult to transfer the price burden down to consumers in a rapid manner. Yet the high oil price has incentivised the entrance of natural gas to the lucrative transport market. The natural gas price in the transport sector is set above $18/MMBtu, which is profitable for imported gas but cheaper than gasoline and diesel prices (for details see Chapter 8).

7 OVERSEAS INVESTMENTS

Since the late 1990s Chinese companies have emerged as the new investor in the global merger and acquisition market, particularly in the oil and gas sector. This demonstrates that China is no longer able to meet its own escalating energy demand and has to rely on external supplies to fuel its growth engine. Furthermore, as the Chinese economy becomes more integrated in the global market, leading Chinese companies are eager to learn about the international market rules and transform themselves into international companies. In the arena of natural gas, two fundamental driving forces underpin Chinese overseas investments: one is to invest in North American shale formation to gain technological know-how for future domestic shale exploration; another is to invest in profitable LNG and upstream gas projects as a commercial equity investor.

7.1 SHALE GAS INVESTMENTS

Chinese NOCs are investing aggressively in North America, with the aim to learn quickly from the industrial leaders[28]. Table 12 summarises the recent Chinese investment in overseas shale gas projects since 2011.

TABLE 12. CHINESE INVESTMENTS IN OVERSEAS SHALE GAS-RELATED PROJECTS

	Date	Type	Investor	Main location	Company	Investment
1	Jan, 2011	Assets & Funding	CNOOC	USA	Chesapeake	$ 2.3 b
2	Oct.2011	Acquisition	Sinopec	Canada	Daylight Energy	$ 2.1 b
3	Jan.2012	Assets &Funding	Sinopec	USA	Devon Energy	$ 2.5 b
4	Feb. 2012	Joint venture	PetroChina	Canada	Groundbirch /Shell	$ 1 b
5	Dec.2012	Acquisition	CNOOC	Canada	Nexen	$ 18 b
6	Dec.2012	Minority stake	PetroChina	Canada	Encana	$ 2.2 b
7	Jan. 2013	Assets & Funding	Sinochem	US	Pioneer	$ 1.7 b
8	Feb. 2013	Assets	Sinopec	USA	Chesapeake	$ 1 b

SOURCE: THE NATURAL GAS OUTLOOK FOR CHINA, DR TILAK K. DOSHI, SINGAPORE, P.14

28 *Overseas Investments by China's NOCs*, IEA 2011

The shale gas boom and depressed domestic price in the US have frustrated many upstream firms and in the meantime brought many overseas investors to the playing field. The typical strategy is that foreign partners join the American E&P firms as minority investors and provide the desperately-needed funding. This is particularly appealing to Chinese investors due to the fact that Chinese companies can then gain relevant exploration experience and technological know-how. From a political perspective, the pouring of critical capital into the shale play by minority non-controlling investors is accepted.

In this context, CNOOC and Chesapeake struck a second deal in early 2011 after their 2010 co-operation in which CNOOC bought one-third of Chesapeake's Eagle Ford shale play project for 1.08 billion dollars. This time, CNOOC bought a 1/3 stake in its partner's lease in Colorado and Wyoming for 570 million dollars and provided nearly 700 million for future drilling funding[29.]

Devon has also tried to raise capital in the equity market. In January 2011, Sinopec bought one-third of stakes in one of Devon's projects for 900 million dollars; in addition, Sinopec provided 1.6 billion dollars of funding for drilling costs[30]. Sinopec also fully acquired Daylight Energy, an exploration company focusing on crude oil, Natural Gas Liquid (NGL), and resource play natural gas based in Alberta and British Columbia.

In January 2013, Sinochem, a major state-owned enterprise specialising in the chemical, agricultural and energy sectors, struck a deal with Pioneer Natural Resources to establish a Joint Venture (JC) in Texas Wolfcamp shale. Sinochem gained ownership of 40% of JC's shale by offering a 500 million upfront cash payment and providing 1.2 billion in capital for JC's future drilling costs[31].

In February 2013, Sinopec made a second deal, gaining further ground in US shale formation. As the second largest US natural gas producer after Exxon, Chesapeake was in a desperate managerial and financial situation: its founder/CEO was soon going to be replaced; the company had refocused on the production of shale oil in the wake of depressing Henry Hub price and plummeting annual earnings; the company has been on an asset sales spree to make up for its rising debt. This time, Chesapeake sold 50 percent of its stake in Mississippi Lime property to Sinopec in exchange for 1 billion dollars, yet Chesapeake remains the project operator[32].

29 *Chesapeake, CNOOC strike second shale deal for $1.3 bn*, Reuters, Jan.30, 2011
Cnooc, Chesapeake Agree on Deal, The Wall Street Journal, Jan.31, 2011
30 *Sinopec Group to Buy Stakes in Devon Energy Oil Projects, Bloomberg*, Jan.4, 2012
31 Energy Intelligence, Jan.31, Oil Daily
32 Financial Times

FIGURE 16. NEXEN'S GLOBAL ASSETS

As mentioned in Chapter 4, some of the deals are set in grand schemes between IOCs and Chinese NOCs. In 2012, PetroChina became a minority stakeholder in Shell's Groundbirch shale-gas project in British Columbia after purchasing a 20% stake. In the meantime, Shell is the best-positioned IOC in Chinese unconventional fields. Shell's CEO said that 'It's part of our global partnership to optimize our business working environment inside and outside China'[33].

PetroChina also recently invested successfully in the Canadian company Encana, after the 2011 failure of negotiations to set up a joint venture. This time, PetroChina acquired 49.9 percent of non-controlling shares of Encana's Duvernay project by paying 1.18 billion in cash plus a future payment of 1 billion Canadian dollars. According to FT's report, the Duvernay project will give PetroChina the experience in 'developing very deep shales that are similar to the Chinese deposits'[34].

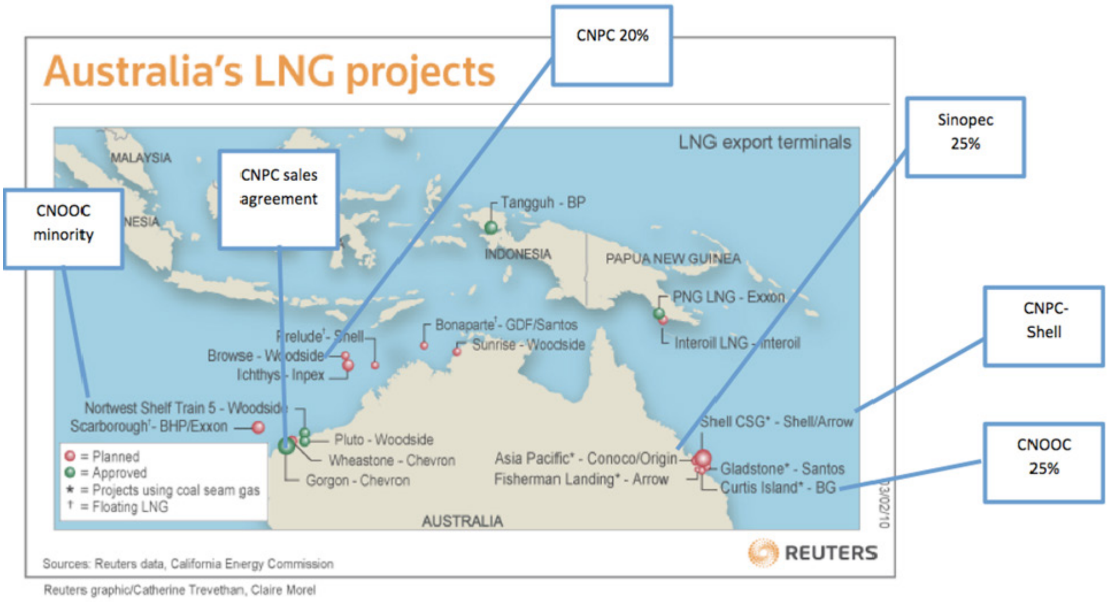
The biggest M&A deal was CNOOC's acquisition of Calgary-based Nexen, an important upstream player producing 207,000 boe/d. This $18-billion deal not only brought CNOOC shale gas assets in Western Canada, Poland and Colombia, but also – and more importantly –significant assets in North Sea, at a daily production rate of 62,000 boe.

33 *PetroChina, Shell Deepen Ties for 'Powerful' Shale Potential*, Bloomberg, Feb.3, 2012
34 *Encana, PetroChina take $2.2 billion stab at joint venture,* Reuters, Dec.13, 2012
Petro China in $2.2bn Canada gas deal, Financial Times, Dec.14, 2012

7.2 LNG PROJECTS

Since the start of Chinese LNG imports in 2006, Chinese NOCs have also been investing in upstream LNG projects. Due to its geographical proximity and the high transport costs of LNG, the Pacific Basin has been the main Chinese investment destination, particularly Australia, which is set to soon become the world's NO.1 LNG exporter (see Figure 17). Chinese investment is the typical strategy of importing countries – investing in upstream projects as equity investors – which is widely used by Japanese and Korean utilities in Australian LNG projects. For example, Woodside Petroleum, the operator of Browse, sold 15 percent of its stake to a Japanese consortium including Mitsui and Mitsubishi.

FIGURE 17. CHINESE INVESTMENTS IN AUSTRALIAN LNG



SOURCES: THE AUTHOR AND REUTERS

TABLE 13. CHINESE INVESTMENTS IN AUSTRALIAN LNG PROJECTS

Project	Company	Operator	Investment	LNG sales (Unit: bcm)	Start year
NWS (conventional)	CNOOC	Woodside	5.3% interest in certain production licences	5	2006
Queensland Curtis (CBM)	CNOOC	BG	25% of the equity	5	2014 2015
Gorgon (conventional)	PetroChina	Chevron		6	2014
Arrow LNG (CBM)	PetroChina	Shell-PetroChina	50% of the equity	Possibly 5.6	Not sanc-tioned
Fisherman (CBM)	PetroChina	LNG Ltd	Tolling agreement with LNG Ltd	2.1	
Browse	PetroChina	Woodside	$1.6 bn for 10%		
APLNG (CBM)	Sinopec	Conoco-Origin	25%	10.6	2015-2016

SOURCES: ENERGY INTELLIGENCE

Australia was the first country to export LNG to China. The very first LNG cargo that arrived in the Dapeng terminal in May 2006 came from the Northwest Shelf Consortium. The contract was signed in the early 2000s with a very appealing pricing term. According to Jonathan Stern's book on international gas pricing, the slope of the oil indexation is 5.25% and the actual price is even lower than $5/MMBtu. However, this first contract built the trust between both sides and opened the door for Australian LNG to enter the Chinese market. Together, CNOOC and CNPC have signed four new contracts with multiple Australian LNG projects, having a total lifted volume of more than 20 bcm/year from 2014 onwards. The volume could ramp up in the future, with further proposals already being discussed.

CNOOC and BG have a comprehensive co-operation. CNOOC first participated in the BG-operated Queensland Curtis LNG (QCLNG) project as a minority investor. In November 2012, CNOOC and BG signed a Heads of Agreement (HOA) that increased BG's LNG sales to China, and CNOOC will increase its shares in the QCLNG project to approximately 25% by investing $1.93 billion. In addition to the original 5 bcm/yr sales from QCLNG starting in 2014, BG will export another 7 bcm/yr of LNG to China starting in 2015. The 7 bcm/yr gas will come not only from QCLNG but also from BG's global portfolio. The update of the QCLNG project includes CNOOC's increasing its ownership in the first LNG train to 50%, CNOOC acquiring interest in certain reserves, and CNOOC and BG jointly investing in two LNG ships in China. BG will remain the operator and will retain 74% of the interest in upstream and infrastructure assets[35].

The planned Shell-Arrow project has changed the ownership scheme a bit. Now CNPC and Shell have entered a 50-50 joint ownership venture of the CBM project as a result of CNPC's $3 billion payment.

In December 2012, CNPC and BHP Billiton entered a deal with the Browse project. In the wake of the recent dramatic cost overrun of the Australian LNG project, driven by soaring labour costs and the strong Australian dollar as well as the mining supermajor's financial underperformance due to falling commodity prices, BHP decided to sell part of its assets in the Browse project. The sales included an 8 percent stake in the East Browse project and a 20 percent share in the West Browse site, which together added up to 10 percent equity in the Browse development as a whole. PetroChina paid 1.6 billion dollars in return. Woodside remains the operator of Browse, with Shell owning 27% of the assets[36].

Sinopec is an investor in the Australian Pacific (APLNG) project, along with ConocoPhilips and Origin. In January 2012, Sinopec decided to pay another $1.1 billion, increasing its share from 10 to 25 percent. Furthermore, Sinopec's original 20-year sale agreement with APLNG will increase from 4.3 to 7.6 mtpa, starting in 2016[37].

7.3 NEW GAS FIELDS

In addition to its LNG projects, China is investing in gas fields. In July 2012, PetroChina acquired 40% of the E&P rights of Qatar Block 4 from GDF Suez, which will remain the operator and largest stakeholder[38]. In Asia Pacific, ConocoPhilips and PetroChina are continuing their strategic partnership. PetroChina will acquire 20 percent equity in ConocoPhilips' offshore assets in the Browse Basin and 29 percent of its onshore assets in the Canning Basin. In return, PetroChina and Conoco signed a Joint Study Agreement (JVA) to study the unconventional Neijiang-Dazu block in China's Sichuan Basin, which may translate into Production Sharing Agreement (PSA) in the near future. ConocoPhilips has already signed a JVA with Sinopec on another shale gas block in Sichuan Basin[39].

35 *BG Group signs Heads of Agreement for sale of QCLNG stake and new LNG supply,* BG Group, Oct.31, 2012
36 Financial Times, Energy Intelligence
37 Reuters
38 CNPC
39 Energy Intelligence

Most recently, as mentioned in Chapter 4, CNPC has moved into East African gas fields. In March 2013, CNPC and Eni struck a 4.2 billion deal for a Mozambican offshore gas field. CNPC will acquire a 20% share of Block 4, which is the most significant discovery. East African gas has a prosperous future, and it is expected that LNG will be developed that will be ready for export to Asia within this decade. Like Shell and ConocoPhilips, ENI also entered the Chinese shale gas basin by co-operating in the Rongchang block in the Sichuan Basin.

8 MINI-LNG INDUSTRY AND GAS IN TRANSPORT[40]

LNG will not only be a means of bringing gas from producing regions into China, but will also affect the domestic gas market. According to Chen Weidong, the chief energy researcher at China National Offshore Oil Corporation (CNOOC)'s Energy Economics Institute, the future of the Chinese domestic gas market will be a combination of pipeline gas and LNG, just like the combination of fixed line telephones and cell phones[41].

8.1 MINI-LNG INDUSTRY

A series of factors underpins the growth of the mini-LNG industry. First of all, the natural gas supply in China is very tight. The demand for clean energy is high, while the pipeline grid is limited. In eastern and southern China, many industrial and urban users still have limited supply of natural gas, especially for peak-shaving purposes and during the winter. Secondly, in regions far from the main transmission pipeline, where it is not economical to build pipeline connections, mini-LNG is an alternative solution for gas supply. In addition, natural gas serves as an alternative fuel in the transportation sector. From the producer's perspective, LNG is also a solution to unlock the potential of stranded gas fields.

Although the mini-LNG industry is nascent, its development is on an upwards trajectory. According to a UBS report, there were 31 liquefaction plants in operation by the end of 2011, with a total capacity of 3.75 bcm; yet the capacity was more than double that a year later, adding 4.76 bcm of liquefaction capacity. In 2013, another 2.35 bcm of capacity is expected to come on board. The majority of liquefaction plants are small-scale: 80% of the plants have under 0.224 bcm of annual capacity, and the smallest plant's annual production is about 0.014 bcm[42].

40 UBS natural gas market report, August 2012
41 Energy Intelligence
42 Xinjiang Guanghui Corporation

TABLE 14. DOMESTIC LIQUEFACTION PLANTS[43]

Time	Number of liquefaction plants	Capacity
In operation before 2012	31	3.75 bcm
Realisation in 2012	16	4.76 bcm
Realisation in 2013	4	2.35 bcm

SOURCE: UBS

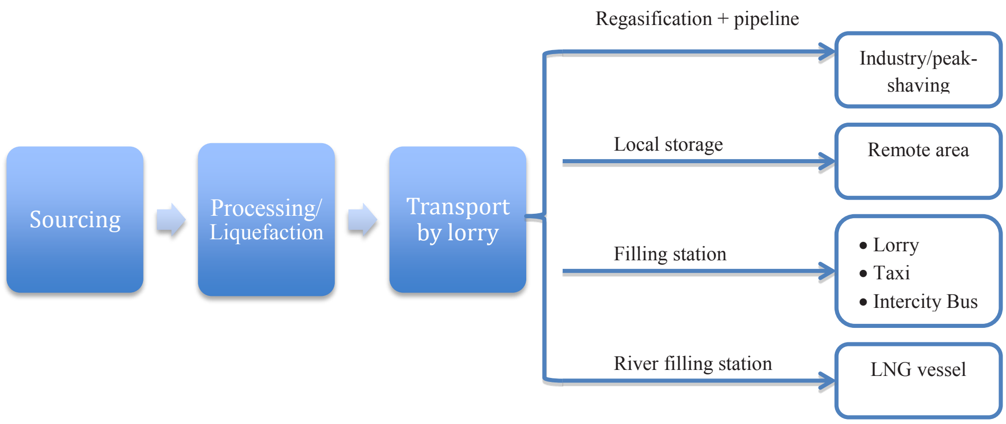
The mini-LNG business model and value chain are reaching maturity. The biggest player in this niche market is Xinjiang Guanghui Energy Corporation, a private enterprise. It owns the largest online LNG liquefaction plant, which produces 0.56 bcm annually. Its LNG business model has epitomised the mini-LNG industry in China. As Figure 19 demonstrates, Xinjiang Guanghui sources LNG, processes it and transports it to end users. It has the largest LNG transportation fleet in China, with more than 600 lorries.

FIGURE 18. LNG TRANSPORTION LORRIES OF XINJIANG GUANGHUI ENERGY CORPORATION

SOURCE: GUANGHUI ENERGY CO.

43 UBS, August

FIGURE 19. MINI-LNG BUSINESS MODEL OF XINJIANG GUANGHUI ENERGY CORPORATION



SOURCE: GUANGHUI ENERGY CO.

8.2 LNG IN TRANSPORT

LNG as a transportation fuel is a main driver of the mini-LNG sector. According to UBS Security research, China's LNG consumption will reach 25.5 bcm in 2015, with 18.9 bcm being used in the transport sector[44]. The government is setting strong incentives for developing alternative fuel in the freight market. In Chapter 2 it was shown that the Natural Gas Guideline has proclaimed natural gas (especially LNG) usage in transportation a priority.

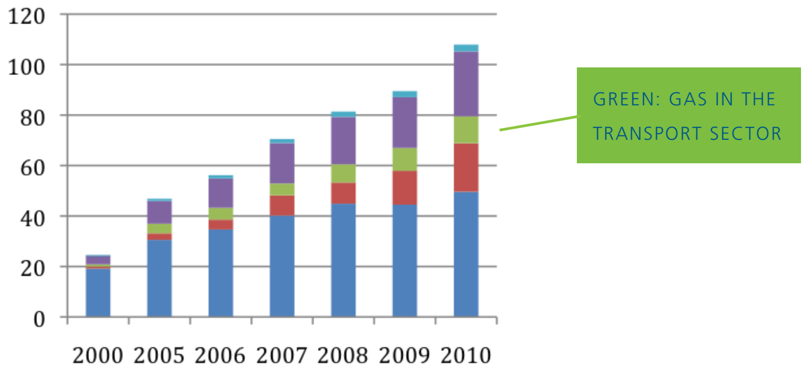
Natural Gas Vehicles are not a new phenomenon in China, but LNG-fuelled fleets are certainly new. Currently CNG-fuelled (Compressed Natural Gas) vehicles widely exist in China, especially in gas-rich regions such as Sichuan. By April 2012, there were 2,338 gas filling stations and 1.1 million NGVs, with 98.9% being CNG-based. The development pace is unprecedented: nearly 25% of the market (230,000 NGVs) came onto the market during the first four months of 2012[45]. While CNG remains dominant, LNG is expected to grow rapidly in the next few years. It is becoming a superior solution for heavy-duty vehicles such as lorries and inter-city transit due to its characteristics. LNG is also considered to be the future fuel of waterborne vessels. Many cities and NOCs have ambitious transport fuel switch plans. CNPC plans to reach 200,000 LNG vehicles, 1,000 LNG-fuelled waterborne boats and 1,500 filling stations by 2015[46]. The city of Hefei is set to become an LNG demonstration city: it will have 20,000 vehicles in its LNG fleet, 1,000 LNG boats, 68 filling stations,

44 UBS, August 2012
45 Hua-Run Gas Corporation
46 *CNPC will expand more than 200,000 LNG automobiles,* xinhuanet, Jun.13, 2012

3 liquefaction plants and 1 storage facility by the end of the 12th Five-Year Plan. By 2012, eight thousand cars had been converted from gasoline to gas[47].

Natural Gas Vehicles are expected to continue to grow rapidly in the years to come, for two underlying reasons. Firstly, natural gas vehicles are seen as a means to mitigate environmental concerns in urban areas, where a large proportion of pollution comes from automobile emissions. Secondly, the high gasoline price and fairly low domestic gas price has created an incentive for a fuel switch. CNG's price is benchmarked at 75% of gasoline; LNG's price is not regulated, but it costs 70-80% of the price of oil products[48]. Also, the big NOCs have a strong desire to develop LNG as fuel. CNOOC, Sinopec and CNPC are all aggressively entering the gas import business, which have caused big financial losses due to the price gap. In the highly-regulated domestic gas pricing regime, gas as a transportation fuel has the highest price. In Table 6, it shows that the end-user price for gas in transport is $20.79/ MMBtu (compared to $9.01/MMBtu in residential sector). Therefore NOCs have an incentive to compete in this lucrative market.

FIGURE 20. NATURAL GAS CONSUMPTION IN THE TRANSPORT SECTOR (BCM)



SOURCE: NATIONAL ENERGY STATISTIC YEARBOOK 2011

47 *The city of Hefei will expand 20,000 LNG autos by the end of 12th plan*, nengyuan.com, Nov.30, 2012
48 *China Hands Big Role in LNG, World Gas Intelligence*, Nov.7, 2012

9 CONCLUSION

The Chinese natural gas industry has entered a golden age. In the quest for cleaner fuels and energy diversification, China has laid out a development strategy to reach its ambitious goals. The government plays an essential role as it seeks to foster the right conditions for market growth. The fixed-price regime will evolve toward a more liberalized one, while on the supply side, domestic production with increasing unconventional sources will underpin a large proportion of demand. Nevertheless, gas imports, both via pipeline and in the form of LNG, will play a significant role. Pipeline imports from Central Asia, Myanmar and Russia could together reach 100 bcm by the end of this decade. LNG imports, especially from Australia, will provide over 50 bcm of annual supply after 2016. In this context, Chinese NOCs are investing aggressively overseas, both to gain technological knows-how in North American shale play, to secure supplies and to optimise commercial profits. In the meantime, a burgeoning mini-LNG industry is emerging to complement the limited pipeline infrastructure.

Looking forward, the Chinese gas sector will be able to secure ample supply from overseas producers. Yet this will expose the Chinese market to increased external risk. On the one hand, China needs to maintain a strong relationship with its neighbouring countries to minimise the political risk. The Ukraine-Russia gas dispute has shown that international pipeline business could spark serious dispute. On the other hand, the tightening LNG market conditions in the medium term, the possibility of rising oil prices, and the oil-indexation formula in gas pricing contracts will pose a significant price risk for Chinese NOCs. Resistance to oil indexation is rising in the region. However, it is uncertain whether the LNG spot market will continue to grow in the Pacific Basin and thus push the market toward a hub-pricing mechanism. China may also consider developing a gas trading exchange with more sophisticated risk management tools. Meanwhile, the domestic pricing reform is key to balancing the price gap.

APPENDIX

1. Natural Gas Data[49] (in bcm)

	Consumption	Energy mix	Production	Import	By pipeline	By LNG
1980	14.1	3.2%	14.2	–	–	–
1985	12.9	2.3%	12.9	–	–	–
1990	15.3	2.1%	15.3	–	–	–
1995	17.7	1.9%	17.9	–	–	–
2000	25	2.3%	27.2	–	–	–
2001	27	2.6%	30	–	–	–
2002	29	2.6%	32	–	–	–
2003	34	2.6%	34	–	–	–
2004	40	2.6%	40	–	–	–
2005	46.8	2.8%	49.3	–	–	–
2006	56.1	3.0%	58.5	0.95	–	0.95
2007	70.5	3.5%	69.2	4	–	4
2008	81.3	2.9%	80.3	4.6	–	4.6
2009	89.5	4.1%	85.2	7.63	–	7.63
2010	107.7	4.6%	94.8	16.5	3.48	13.02
2011	130.7	5%	102.5	31.4	15	16.4
2012[49]	147	–	107.7	42.66	22.79	19.87
2013 est	165	5.8%	115	53	30	22.77

49 China Energy Statistical Year Book 2011, Zhou Jiping, IGU, 2012; UBS China Natural Gas Monthly, July 2012; GIIGNL, The LNG Industry 2011

50 The last two rows' data come from Int'l Oil Daily, Jan.29, 2013

2. Gas use by sector[51] (in bcm)

	1980	1985	1990	1995	2000	2005	2006	2007	2008	2009	2010
Industry	13.7	12.4	13.1	15.43	19.98	33.15	38.57	48.21	53.3	57.9	68.82
Mining				5.2	7.2	8.3	8.2	9.1	11	12.3	13.7
Manufacturing				10.1	11.9	22	26.3	30.9	33.8	32.1	35.8
Electricity, gas, water production and supply				0.17	0.81	2.6	3.9	8	8.4	13.4	19.2
Construction	0.6	1.4	1.1	0.03	0.08	0.15	0.17	0.21	0.1	0.1	0.12
Transport, storage, post	0.07	0.08	0.2	0.16	0.88	3.8	4.7	4.7	7.2	9.1	10.7
Wholesale, retail, hotel, restaurant				0.06	0.34	1.08	1.32	1.71	1.78	2.4	2.7
Residential	0.2	0.43	1.86	1.94	3.23	7.94	10.3	14.3	17	17.7	23
Other	0.05	0.05	0.12	0.12	0.06	0.9	1.3	1.6	2.1	2.4	2.7

3. 2011 Chinese LNG Import Data (in bcm)

	Egypt	Eua. Guin.	Nigeria	Peru	Trinidad & Tobago	Qatar	Yemen	Australia	USA	Indonesia	Malaysia	Russia	**Total**
Import	0.25	0.16	0.88	0.18	0.40	3.02	0.88	4.66	0.18	3.28	2.27	0.38	**16.6**
Spot & S-T	0.15	0.16	0.88	0.18	0.40	0.24	0.25	0	0.18	0	0.23	0.16	**2.83**
%	60%	100%	100%	100%	100%	8%	28%	0	100%	0	10%	42%	**17%**

4. 2012 January-October Chinese LNG Import Data (units: price in $/MMBtu, volume in million tons)

	Algeria	Australia	Indonesia	Malaysia	Oman	Qatar	Egypt	Nigeria	Russia	Trinidad	Yemen	**Total**
Price	16.72	3.42	4.17	8.13	15.75	19.12	15.04	16.23	18.46	7.76	13.81	**10.78**
Volume	0,061	2,979	2,063	1,453	0,063	4,031	0,058	0,179	0,315	0,051	0,535	**11,789**

51 China Energy Statistical Year Book 2011

5. Table 7. LNG receiving terminals[52]

		Operation	Status	Capacity (bcm/y)	Shareholders
1	Guandong Dapeng 广东大鹏	2006	In operation	5.2	CNOOC 33% BP 30%
2	Fujian Putian 福建莆田	2009	In operation	3.6	CNOOC 60% Fijian Development and Investment Co. 40%
3	Shanghai 上海	2010	In operation	4.1	CNOOC 45% Shanghai Shenergy Group 55%
4	Jiangsu Rudong 江苏如东	2011	In operation	4.9	CNPC Kunlun 55% Pacific Oil and Gas 35% Jiangsu Guoxin Investment 10%
5	Liaoning Dalian 辽宁大连	2011	In operation	4.2	CNPC Kunlun 75% Dalian Port 20%
6	Zhejiang Ningbo 浙江宁波[53]	2012	In operation	4.2	CNOOC 51% Zhejiang Energy 29% Ningbo Power 20%
7	Guangdong Dongguan 广东东莞[54]	2013	In operation	4.7	JOVO
8	Guangdong Zhuhai 广东珠海[55]	2013	Under construction	4.9	CNOOC 30% Guangdong Power 25% Guangdong Gas 25%
9	Hebei Caofeidian 河北曹妃[56]	2013	Under construction	4.8	CNPC 51% Beijing Investment Holding Company 29% Heibei Construction Investment Company 20%
10	ShandongQingdao 山东青岛[57]	2014	Under construction	4.1	Sinopec Huaneng Group
11	Hainan Yangpu 海南洋浦[58]	2014	Under construction	4.2	CNOOC 65% Hainan Development Holdings 35%
12	Shenzhen 深圳[59]	2015	Under construction	5.6	CNOOC 70% Shenzhen Energy 30%
	Fujian Putian 福建莆田 phase II	—	Under construction	3.4	CNOOC
13	Guangxin Beihai 广西北海	2015	Under construction	4.2	Sinopec

In operation: 30.9 bcm
Under construction: 31.2 bcm
Total: 62.1 bcm

52 *Gas Pricing and Regulation, China's Challenges and IEA Experience,* IEA 2012, P. 25-26, UBS China Gas Month Report, February, 2012
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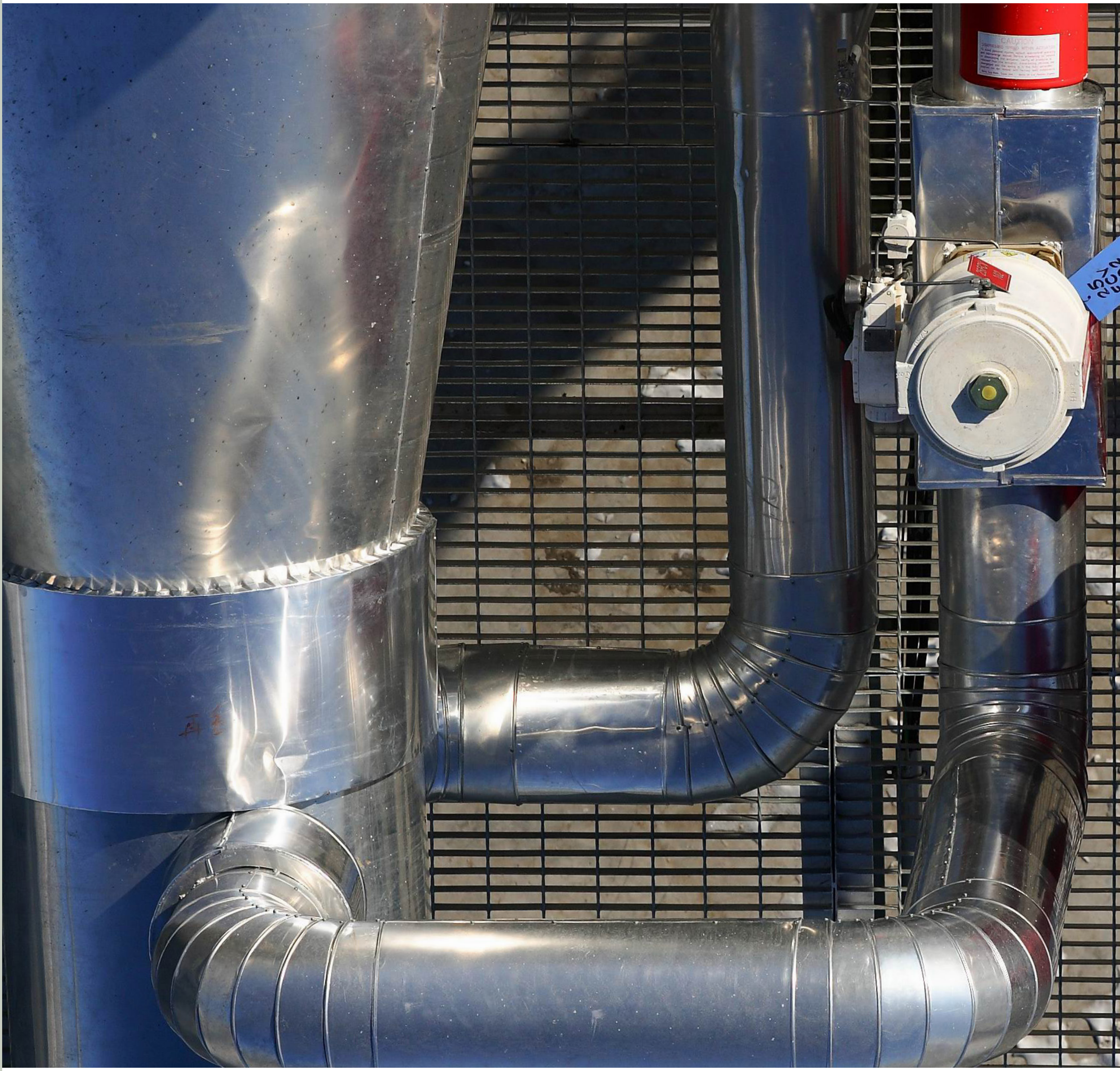

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