IDENTIFYING POLICIES AND IMPLEMENTATION STRATEGIES FOR IMPROVING ENERGY EFFICIENCY

CASE STUDY 3

Increased Utilisation of Natural Gas in China

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1. Introduction

This report is the final in a series of case study reports on findings arising from the broader study into achieving increased energy efficiency in China. This report examines the potential for the increased utilisation of natural gas in China, including the opportunities and constraints facing the industry. Natural gas in China is entering a new and important phase as a transition fuel towards a low carbon economy. While domestic production of natural gas has expanded, it has been unable to meet the rapid growth in demand. Consequently, China has recently embarked on a policy of importing gas from overseas via pipeline and shipped LNG. To distribute the gas, an ambitious national pipeline network has been rolled out supported by the construction of tankers, ports, storage, gasification and liquefaction facilities. At the same time, the central government has been reforming the policy and regulatory framework governing the gas market to encourage its expansion.

The growth in annual consumption of natural gas in China exceeded both coal and oil between 2000 and 2008 when it rose 16.2% on average. This is nearly 10 percentage points higher than the annual growth rate of oil consumption and 6.6 percentage points higher than coal consumption's annual growth rate. Between 2000 and 2009 natural gas production grew by an average of 13.2%. In 2009, almost 83 bcm of natural gas was produced domestically. While most of China's natural gas comes from domestic production, imported gas supplies are making up an increasing proportion of consumption. China is rapidly expanding its investments in international gas supplies to ensure a diverse and secure supply especially while international gas prices remain depressed. Moreover, expectations within China of strong gas demand in the coming decade, both regionally and internationally, are resulting in many gas projects being brought forward, including several LNG ports and new field developments. China currently imports or has long-term supply contracts to import gas from Australia, Indonesia, Malaysia, Qatar and Turkmenistan. It also has initial agreements to buy gas from Russia, Papua New Guinea, Kazakhstan, Iran and Myanmar.

This report commences by setting the context around China's energy mix followed by a discussion of the role of natural gas in China, including the nation's gas resources, demand and market characteristics. China's national gas policy framework is then introduced before exploring the future of gas demand and the implications for supplies, infrastructure, unconventional gas resources and investment in the sector. The global and regional supply position for natural gas is then briefly discussed before presenting several policy options for increasing the utilisation of natural gas in China.

1.1. Background

Several factors shape China's current and future energy mix, including: China's national endowment of energy resources; its historical energy utilisation; energy security concerns; the cost of natural gas; the rate of economic growth and pattern of development; population growth; urbanisation; and, environmental considerations. Each of these factors encompasses many complicated issues and could be examined at length. Therefore, the issue of energy security, for instance, while probably the most important determinant of China's energy policy, is not the focus of this report. Instead, this report looks at the potential role of natural gas in improving the efficiency of China's energy mix with a particular focus on reducing carbon emissions. Before introducing the role of natural gas in China, it is necessary to briefly describe the two primary drivers for increasing energy demand in China: the structure of the economy and the nation's demographics.

In 2010, China became the second largest economy in the world and the world's largest trading nation. It has clearly led the global economic recovery following the effects of the financial crisis and is an engine of world economic growth. In the next two decades, it is predicted that China will surpass the United States to become the world's largest economy. It has maintained a sustained rate of rapid economic growth of nearly 10% over the past three decades and is predicted to continue to do so for a further two to three decades (CSES, 2010). In terms of demographics, China has the world's largest population of around 1.33 billion with almost half living in cities. It has the best record in reducing poverty and today boasts one of the world's fastest growing affluent populations. By 2030, one billion will be urban residents in one of the 233 cities with over one million people (McKinsey, 2009b). This will require a further five billion square metres of paved roads, the construction of a further 170 mass transit systems and 50,000 skyscrapers with 40 billion sq meters of floor space and an economy that is at least four times as large as today.

All this requires a lot of energy. As a result, China became the world's largest consumer of energy in 2010. In the next two decades, China will install more new electricity generating capacity than currently exists in the United States today (IEA, 2007). Most of this new capacity will burn coal with 105GW of thermal coal power brought online in 2006. A further 80GW of coal power generators were completed in 2008 (IEA 2009: Cleaner Coal in China; NBSC, 2010). This recent rapid spike in coal power is expected to moderate at around 50GW per year after 2010 according to ERI (CEACER, 2009). Due to the country's high dependence upon coal, China became the world's largest emitter of greenhouse gases (GHG) in 2006. The past three decades of rapid economic growth have had an enormous environmental impact with high levels of serious air, water and soil pollution. It is predicted, however, that China's path along the environmental Kuznets curve is expected to be rapid, relative to most developed and developing nations.

According to Figure 1, the IEA (2009a) estimates global primary energy demand to grow by 1.5% annually between 2007 and 2030, with most of the growth driven by China (2.9%) and India (3.4%). Electricity consumption in non-OECD countries is the main driver for rising energy demand. China will play a key role adding nearly 1400 GW of new power-generation capacity by 2030; representing nearly a third of the global total.

Fig. 1. Primary Energy Demand by Region in the IEA's Reference Scenario (Mtoe)

	1980	2000	2007	2015	2030	2007-2030*
OECD	4050	5249	5496	5458	5811	0.20%
European Union	n.a.	1684	1757	1711	1781	0.10%
North America	2092	2682	2793	2778	2974	0.30%
United States	1802	2280	2337	2291	2396	0.10%
Europe	1493	1735	1826	1788	1894	0.20%
Pacific	464	832	877	892	943	0.30%
Japan	345	518	514	489	488	-0.20%
Non-OECD	3003	4507	6187	7679	10529	2.30%
E. Europe/Eurasia	1242	1008	1114	1161	1354	0.90%
Russia	n.a.	611	665	700	812	0.90%
Asia	1068	2164	3346	4468	6456	2.90%
China	**603**	**1105**	**1970**	**2783**	**3827**	**2.90%**
India	207	457	595	764	1287	3.40%
Middle East	149	389	513	612	903	2.50%
Africa	128	378	546	702	1030	2.80%
Latin America	274	499	630	716	873	1.40%
Brazil	292	457	551	633	816	1.70%
World**	7228	10018	12013	13488	16790	1.50%

Notes: * Compound average annual growth rate. ** World includes international marine and aviation bunkers (not included in regional totals).

Source: IEA World Energy Outlook 2009

In terms of the energy mix, the IEA predict that coal, natural gas and renewables will take up some of declining supply of oil with coal remaining the core energy source and actually rising to 44% of the global total by 2030. The situation in China is expected to be little different, despite Chinese government policies promoting a low carbon economy, with coal continuing to play the dominant role for future energy demand. Coal provides energy security due to its low cost and relative abundance, primarily located in the northern and north eastern regions of the country. In contrast, China is largely reliant on imports for its oil requirements.

Fig. 2. Comparison of Air Pollutant Emissions from Various Energy Sources, kg

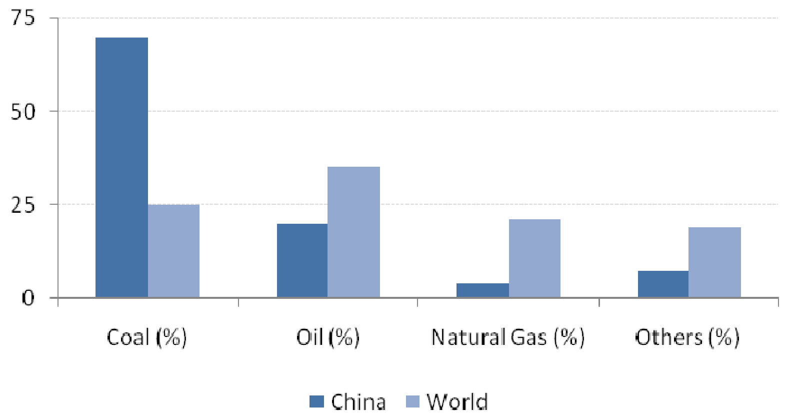
	Coal	Fuel oil	Natural gas
CO_2	6.2580	3.3320	2.1840
SO_2	0.0506	0.0420	0.0002
NO_X	0.0218	0.0069	0.0026

Source: Higashi, 2009

As shown in figures 3 and 4, China remains heavily dependent upon coal and oil for its energy needs with natural gas representing around 4% of the energy mix. This is around 6 times smaller than the rest of the world's average mix. Despite the initially low figure, the Higashi (2009) estimate China's primary natural gas demand will grow at around 5.3% annually between 2007 and 2030 from 73 bcm to 242 bcm. The stronger growth of natural gas is driven by the government's desire to diversify China's energy mix, improve energy efficiency, switch to lower carbon emitting energy sources and reduce air pollution. Figure 2 highlights the significant air pollutant emission benefits of natural gas vis-à-vis coal and fuel oil with around 35% reduced carbon, almost zero sulphur dioxide and less than 12% of nitrogen oxide emissions compared with coal. In addition gas emits virtually no particulates.

In addition to the reduced air pollutant emissions from natural gas, the energy efficiency of combined cycle gas turbines is 55% relative to the most efficient advanced super critical coal-fired power plants at below 40% (IEA, 2009b). As discussed in the CSES (2010) report, *The transition to a low carbon economy: implementation issues and constraints within China's changing economic structure*, the government has introduced a comprehensive range of policy measures for energy intensive industries with specific energy efficiency and pollution reduction targets. As a result of these measures, many of the higher value added industries are switching to natural gas as a fuel source.

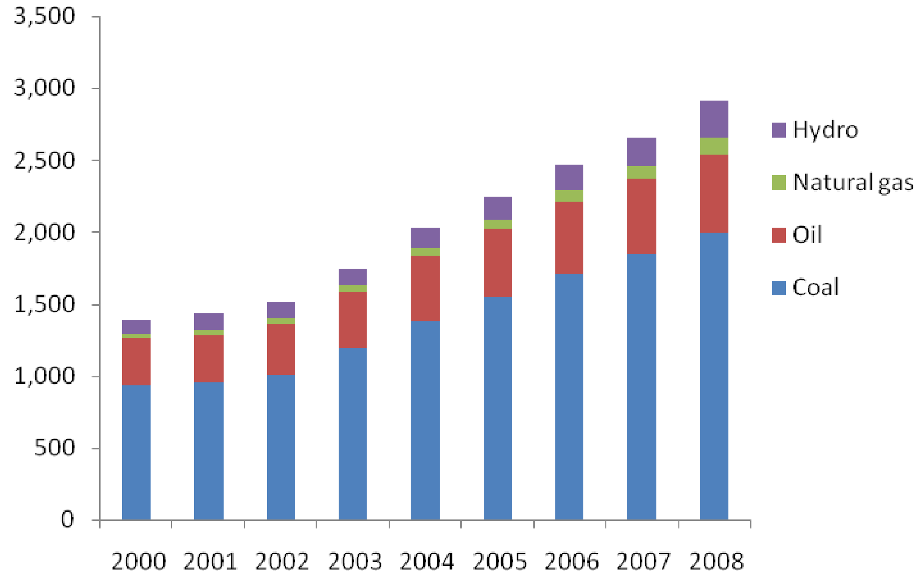
Fig. 3. Coal and Oil Dominate China's Energy Consumption



Source: Source: IEA, 2009a

Figure 4 illustrates the strong growth in the consumption of electricity in China, which doubled between 2002 and 2008. Each segment of the energy mix has generally maintained its share during the period 2000-2008 with increases in the proportion of coal (from 67.8% to 68.7%), natural gas (from 2.4% to 3.8%) and hydro (from 6.7% to 8.9%) whereas the share of oil has declined from 23.2% to 18.7%. In 2009, China consumed an estimated 3.1 billion tonnes of standard coal equivalent (btsce). In terms of future patterns of energy demand, the IEA (2009a) estimates China's primary energy demand will further rise to around 3,827 Mtce by 2030. This is based upon annual growth of 2.9% in their reference scenario. Due to the preeminent position of coal in China's energy mix, the IEA estimates that China will account for 65% of the global increase in coal demand between 2007 and 2030. Apart from hydro-power, other primary energy sources are relatively immature at this stage. The annual doubling of wind power capacity during the past four years and the strong growth of natural gas are notable, but the speed of economic growth and energy consumption continues to reinforce coal's dominant position.

Fig. 4. Energy Consumption by Source, million tons of standard coal equivalent (Mtce)



Source: CEIC Data (2010) from National Bureau of Statistics China

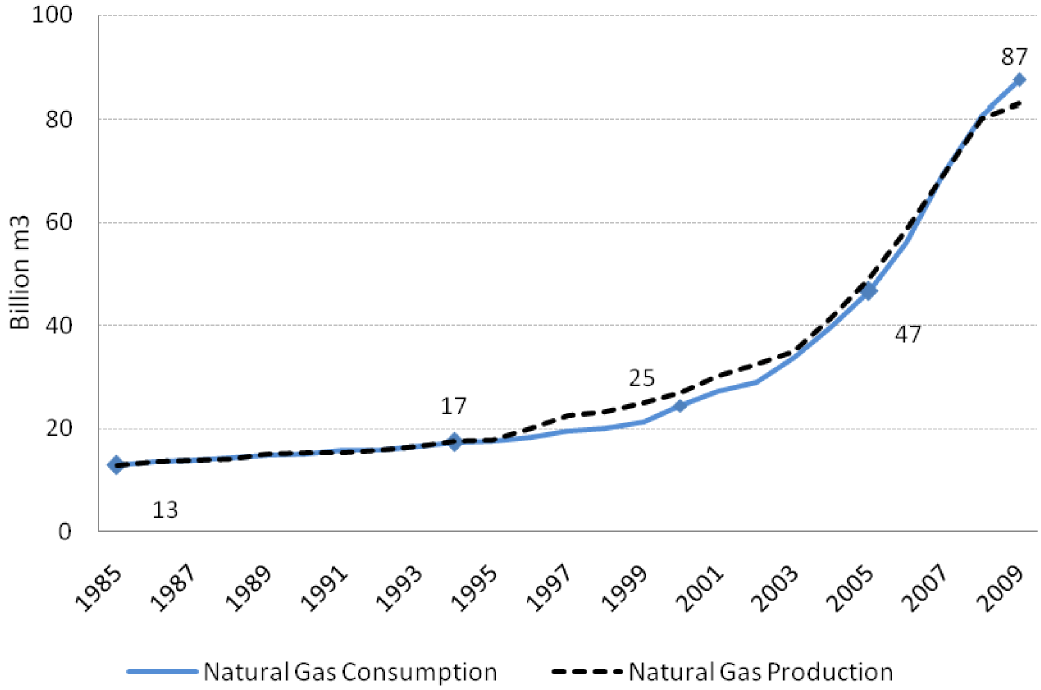
2. Natural Gas in China

This section reviews some of the background context surrounding China's current and future energy mix with a focus on the demand and use of natural gas. A key focus is on the future potential of natural gas to provide China with a clean and reliable transition fuel towards a low carbon economy.

The production of natural gas in China has grown steadily during the past decade from 27 bcm in 2000 to 86 bcm in 2009 largely due the construction of a high-pressure, west-east pipeline and spur lines. The west-east pipeline has had a dual effect of encouraging the development of gas resources in the western and central provinces to supply large cities along the eastern seaboard. By 2015, the Ministry of Land and Resources estimate domestic gas production to reach 160 bcm (Wang, 2009). Whereas the IEA (2009a) recently suggested Chinese gas production will only reach 100 bcm by 2015. A figure that is most likely to be exceeded by 2010. While the IEA is expected to revise this figure in 2010, they argued that such expansion in gas production may prove hard to maintain in the longer term due to the sector's modest growth until quite recently with very little infrastructure to bridge gas supply in the west with gas demand in the east of the country. However, this section explains how China has in fact invested heavily in the expansion of exploration, processing and distribution of gas resources whilst reforming the relevant policy and regulatory frameworks to ameliorate existing strain between demand and supply.

Figure 5 shows the steady growth in natural gas consumption and production since 2001. Until recently, nearly all of this gas demand has been met by domestic supplies. However, this relationship is entering a new phase. While domestic gas production is expected to grow with the development of new onshore and offshore fields as well as significant unconventional gas resources, domestic gas resources are expected to fall behind the strong domestic demand for natural gas. As a result, China's modest imports of gas are expected to grow rapidly shifting the country from self-sufficiency to a position of increasing dependence on gas imports. It is possible that half of China's gas needs will be met by imports by 2020. In order to facilitate this transition, China has invested heavily in both hard and soft gas infrastructure. In 2006, China's first LNG terminal at Dapeng in Guangdong received its first shipment of gas from Australia's North West Shelf. Then in 2009, pipelines connecting Central Asia to China were completed. Additional infrastructure investments have included the exploration and development of new fields, the construction of pipelines, LNG terminals, storage, liquefaction and gasification facilities. Commercial developments include overseas investments in gas companies, gas fields, and joint venture exploration and development projects.[1]

Fig. 5: Total Natural Gas Consumption and Production, 1985-2009



Source: NBSC, 2010

2.1. China's Natural Gas Resources

A CNPC 2005 gas survey estimated China's resources amounted to 56 trillion cubic metres (tcm). A more recent national survey (Figure 6) estimated total gas reserves of 45.58 tcm with 3 tcm of proven reserves, 17.4 tcm of verified resources and 1.65 of recoverable reserves. The IEA (2009a) estimated China has 2.7 tcm of proven reserves. China's gas reserves are mainly located in the north western and central regions of the country, whilst energy needs are concentrated in China's eastern cities. The largest gas fields are located in the Tarim and Junggar, Ordos and Sichuan basins. The largest fields include the 530 bcm Sulige and Changqing fields in the Ordos Basin with 2009 production at around 19 bcm and the 100-bcm Klameli field in the Junggar Basin. Offshore gas fields are found in the Bohai Sea, East China Sea and South China Sea. New coal bed methane resources are

[1] The 2010 Singapore-Chinese investment in Chesapeake Energy provides a good example of strategic partnerships that will accelerate the development of China's gas industry, particularly its unconventional gas reserves. Chesapeake is one the largest US companies in the shale gas sector.

being discovered with around 134 bcm in proven supplies and 76 bcm economically recoverable out of a total estimated reserve of 36.81 tcm.

Fig. 6. China's Distribution of Prospective Natural Gas Resources, 2007

Region	Total resources, trillion m^3 (tcm)	Utilised		Proven reserves		Verified reserves tcm	Recoverable reserves tcm
		Resource amount, tcm	Rate of conversion (%)	Capacity, tcm	Proven rate (%)		
National	45.58	20.51	45	3.107	15.15	17.4	1.651
On-shore	37.38	17.23	46	2.752	15.97	14.48	1.416
Eastern	5.04	2.77	55	0.978	35.25	1.8	0.407
Central	17.36	7.81	45	1.028	13.16	6.78	0.631
Western	13.06	5.88	45	0.742	12.62	5.14	0.376
Other	1.91	0.76	40	0.0047	0.62	0.76	0.003
Off-shore	8.2	-	40	0.359	10.95	2.92	0.237

Source: China Chemical Industries Yearbook (2008)

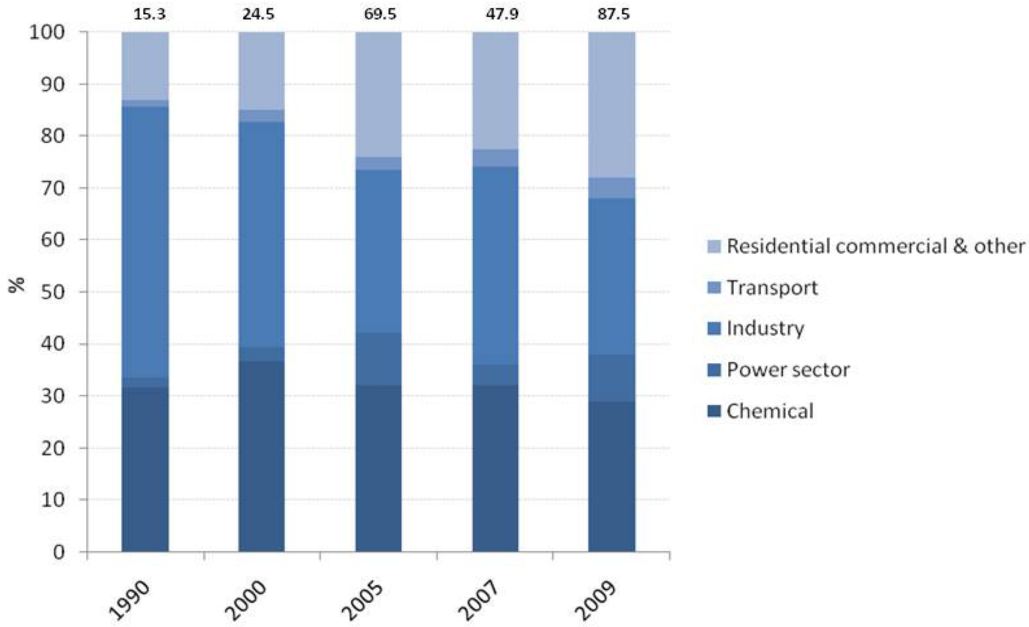
China has the world's third-largest estimated reserves of coal seam gas, at 36.81 trillion cubic metres (tcm) with 6.34 tcm in so-called verified workable natural gas reserves and 161 bcm of proven reserves.[2] Approximately 10 tcm or one third of China's CBM reserves are located in Shanxi Province, which recently announced plans to combine its gas reserves (coal-bed gas, natural gas, coke oven gas and substitute natural gas) into a single network (SinoCast Energy Beat, 2010). It would then connect to the West-East pipeline for the supply of up to 12bcm annually from 2015.Slow progress in exploiting CSM in recent years due to the industry fragmentation, pricing difficulties and technological impediments. Technical and geological difficulties will remain challenging for the CSM industry, but the key problem is a lack of willingness to invest due to uncertain pricing and market conditions. In addition, initial surveys of methane hydrate reserves estimate China has around 35 billion tonnes of oil equivalent located in frozen tundra and under the ocean floor (Zhang, 2009).

2.2. Domestic Natural Gas Consumption

In order to secure and diversify the country's energy mix, improve energy efficiency and reduce air pollution, the government has introduced policy measures supporting the development of a downstream gas industry. While gas remains only a small percentage of the total primary energy mix, domestic gas consumption has tripled over the past decade in China and is set to more than double by 2020 from the current 4% of total energy use to nearly 10%. This is set against a background of steady growth since the mid 1990s as shown in Figure 5 from 15.3 billion cubic meters in 1993 to 87.5 bcm in 2009.

[2] Sinopec claims that it holds 1.1 bcm of CBM reserve with 375 mcm identified as recoverable (Xinhua, 2010b).

Fig. 7: China's natural gas consumption and structure, 1990-2009, bcm



Source: CEACER, 2009, p.855; interview with ERI researchers

Figure 7 illustrates the breakdown of natural gas consumption between 1990 and 2009. In 2009, natural gas consumption (including methane) was equally distributed between industrial, chemical and residential users at around 30% with the remainder used for power generation and transport. Throughout the period, fertiliser production remains the most stable and single largest user of natural gas, supplying farmers with subsidised feedstock. In 2009, the nation's fertilizer industry consumed nearly 10 bcm of gas, accounting for around 20% of the nation's total gas consumption due to the low subsidised domestic gas prices (China Chemical Reporter, 2010). The structure of gas consumption is clearly quite variable from one year to the next, reflecting in some respects the immaturity of the market as well as the ability for users to switch fuels as a result of supply and price consideration. The clearest pattern emerging from Figure 7 is that the industrial sector's use is gradually declining with residential and commercial users expanding. ERI researchers expect residential demand to continue to experience strong growth together with the power sector.

In 2009, China produced 83 bcm of gas while consumption rose 11.5% for the year to 87.45 bcm, leaving a gradually increasing shortfall of around 4.5 bcm which was supplied by pipeline and shipped LNG. Despite a global drop in demand for gas following the global financial crisis (GFC), China experienced shortfalls in gas supply due to a combination of the colder 2009-2010 winter, chemical and petrochemical overproduction and rapidly growing urban demand. For instance, Beijing's daily natural gas consumption recently hit a high of 53 million cubic meters. As a result, industrial users were required to curtail use so as to free up supplies for household heating.[3]

[3] An investigation into the 2009/2010 winter gas shortages revealed that supplies were around 30 mcm short per day across China with specific shortages of: 300 000 cubic meters in Hangzhou; 600 000 cubic meters in

Industrial Use

Industrial use of natural gas is mainly used as a fuel and feedstock in several industries such as ammonia, methanol and chemical fertilizer production. Fertilizer producers, in particular, have been allocated cheap gas for feedstock because of the industrial and social policy for supporting farmers. Other major natural gas consumers in China's industrial sector include the energy sector, which uses gas mainly for the development of oil and gas fields, and the chemicals and petrochemicals industries for feedstock and fuel. Up until late 2007, an increasing number of chemicals and petrochemical industries were tapping in to domestic subsidised gas supplies to reduce their operating costs due to the rising price of oil. As a result, since 2008 the use of natural gas by industry, with the exception of fertiliser production, has been restricted by adjustments in policy.

Power Generation

Gas has been presented as the transition fuel for a carbon constrained energy market offering cleaner, lower cost and flexible power generation capacity that can substitute for base load and peaking coal-fired power as well as offering complementary and cost-effective base load power supplies when linked up with intermittent renewable sources, such as wind and solar. Gas powered turbines are effectively turn-key operations that can be switched on or off as renewable supplies ebb and flow.

Another possibility for increasing the competitiveness of gas vis-à-vis coal is through the Clean Development Mechanism (CDM). CBM provides a potential funding stream for the development of gas-fired cogeneration heat and power (CCGT) units as well as the development of new CBM fields due to the abatement potential of trapping the methane from coal mines. Utilising gas from coal fields improves mine safety and reduces the potential emissions from methane. So far, over half of global CDM funding has gone to China, mostly to renewable energy developments, such as promoting hydro, wind and solar, but it has also gone to coal seam methane projects.

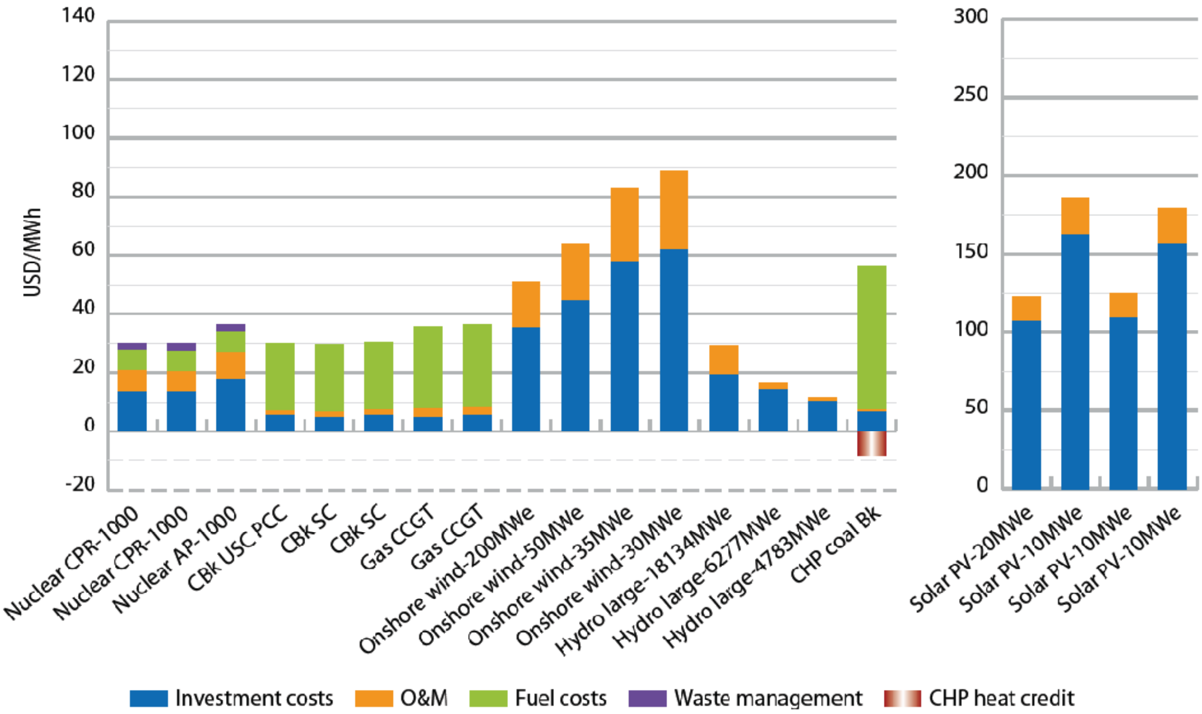
New integrated combined cycle gas (ICCG) turbines generate around 30%-40% of the carbon emissions of coal power plants and cost around US$1 million per megawatt of capacity to build. The combination of a recent spike in gas prices and the construction of new super critical and ultra-super-critical coal-fired power generators in China, which are more efficient and less polluting than standard coal power plants, has reduced some of the demand for gas-fired power plants. According to the IEA et al. (2010) these new coal power plants cost around US$29.42 per MWh to generate electricity compared to gas at US$35.81 MWh (Figure 8). The investment costs and operation and management costs of both coal and gas-fired power plants are comparable. However, the higher fuel costs of gas are what differentiate the two fuels. The OECD price assumptions for the two fuels were US$86.34 per tonne of coal or US$2.95 per GJ compared with gas at US$4.78 per MMBtu (Million Metric British Thermal Units) or US$4.53 per GJ. In contrast, China's energy options ranged from the cheapest for hydro at US$11.49 MWh, coal (without CCS) at $29.42 MWh, nuclear at $29.82 MWh, gas at $35.81 MWh, wind at $50.95 MWh and solar at $122.86 MWh.[4] While gas currently remains a

Xi'an; 700 000 cubic meters in Wuhan; and 8 million cubic meters in Sichuan and Chongqing (China Chemical Reporter, 2010).

[4] These figures are based upon 'lowest cost' of several options and include a 5% discount rate (IEA & NEA, 2010).

higher cost power generation fuel compared to coal (in the absence of a carbon tax), new highly efficient combined cycle gas turbine (CCGT) plants are a possible replacement for decommissioning older coal power plants.[5] It is also important to note that these prices do not incorporate any of the cost associated with the health and environmental implications of sourcing and burning either fuel.

Fig. 8. Electricity Generation Costs by Fuel and Type for China



Source: IEA et al., 2010, 83

To date, the use of gas for power generation has been somewhat subdued in China due to a combination of regulatory, pricing and supply constraints. Currently, gas-fired generators produced around 4GW of electricity in 2009 with an ambitious target of increasing that to 36 GW by 2011 and 50 GW[6] in 2020 (WEFN, 2009; CEACER 2050). Most of existing gas-power generation capacity is located in the Yangtze River Delta region with Guangdong and Fujian more recently committing to a further 10 GW of new gas-fired power generation. The construction of gas-fired power generation in both of these regions was supported to guarantee adequate demand for the West-East gas pipelines. However, due to surging industrial and residential demand for gas, many of these new power plants have been operating at reduced capacity due to shortage of supply. Following the arrival of new gas

[5] Several industry studies have reviewed the potential for gas to replace coal power generation in the UK, EU, US and Hong Kong. Estimates for Hong Kong showed that a 10% carbon abatement could be achieved by doubling the share of natural gas in the electricity mix, but retail costs could rise by 20% (Ng, 2009). A Bloomberg New Energy Finance (2010) report for the US, estimated the cost of a coal to gas fuel switch for the existing power sector to cost around US$90-95 per ton of abated CO2 equivalent. Instead, greater benefits and cost-effectiveness can be achieved through the gradual replacement of retiring the most inefficient coal power plants with gas plants and the use of gas as a complementary back-up for renewables.

[6] This is a reduction from the original 2007 government target of 70 GW by 2020.

supplies after 2011, it is expected that power generation will be the most important driver of gas demand through to 2030 (IEA, 2009a).[7]

Although natural gas consumption in the power sector is steadily increasing, it represented only an 11.6% share in total gas consumption in 2007, largely because the infrastructure is not on stream. In addition, the expansion of natural gas as a power generation fuel has been until recently limited due to government policies that restricted its expansion. The main reason for this policy was concern with protecting the coal industry and the high cost of natural gas. As a result, natural gas has struggled somewhat to keep up with the strong growth of coal and the renewable sector in China's energy mix. A 2005 target set by the NDRC called for the doubling of gas in China's energy mix from 2.5%-2.8% in 2005 to 5.6% by 2010. However, it is unlikely to be met due to the strong growth of the broader economy, especially the industrial sector, which remains heavily reliant on coal.

China's natural gas utilisation policy is already shifting away from limiting gas power generation to encouraging it as an alternative cleaner form of energy. A key component of this shift relates to the need to diversify the nation's energy mix, the recent drop in international gas prices, the abundant domestic supplies of coal bed methane, access to technology and methods for its economical extraction, the need to reduce air pollution and mitigate China's carbon emissions. Therefore, according to the government's long-term electricity development plan, gas-fired power capacity is expected to reach 70 GW by 2020 (a more recent plan shows capacity of 36 GW by 2010). However, the competitiveness of natural gas prices compared to coal has aroused uncertainties about the plan

Residential Use

Traditionally, most households burnt coal briquettes or coal gas for residential heating and cooking. But due to the health and environmental problems arising from coal use, many cities switched to LPG. However, today natural gas now leads both coal gas and LPG as the preferred option due to its health and safety benefits and lower price (Figure 2). The household price of natural gas in the southern cities of Shenzhen, Guangzhou, Dongguan and Foshan ranges from RMB3.45 to RMB3.8 per cubic metre. The number of urban residents with access to gas doubled from 32 million in 2001 to 71 million in 2005. By the end of 2008, 90% of the urban population had access to gas for heating and cooking due to the construction of gas pipeline networks and distributed supplies around domestic fields, as well as spur lines from the West-East pipeline or LNG import ports. In late 2007, the government introduced a new priority sector policy for natural gas, which categorised city residential use and combined systems for heat and power as the top priority. As a result, residential gas use has grown by an average of 25% during the past decade. Earlier IEA (2007) estimates predicted the number of Chinese cities with gas distribution to rise to 270 in 2010. The long-term target for residential gas is 65% urban penetration by 2050. In order to meet current demand and realise the long-term targets, many cities across the nation are being connected to ever-expanding national gas network of pipelines.

[7] An earlier de-linking of oil-gas pricing and a shift to spot market pricing may expedite gas demand within the power sector.

Fig. 9. City Gas Prices, China, 2007

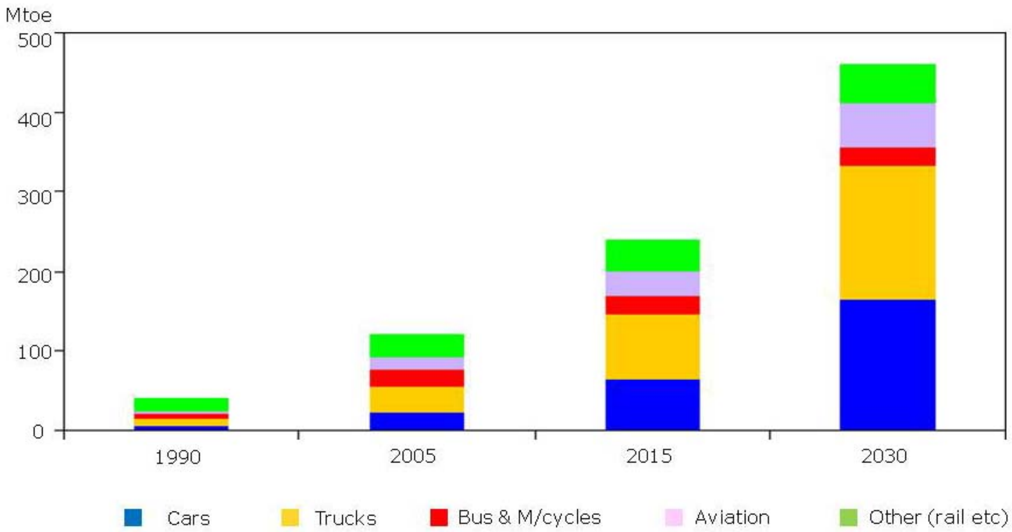
Fuel	Thermal value	Unit price	Calorimetrical value price
Natural gas	8 300 (kcal/m3)	2.19 (RMB/m^3)	0.264 (RMB/million cal)
LPG	12 000 (kcal/kg)	2.19 (RMB/kg)	0.490 (CNY/million cal)
Coal gas	3 600 (kcal/m3)	1.0 (RMB/m^3)	0.278 (RMB/million cal)

Source: Higashi, 2009

Transportation

Natural gas use in transportation is another sector being promoted by local governments concerned with the rising price of oil and the need to reduce air pollutants. In many cities, such as Chengdu, Harbin and Beijing, nearly all public buses and many taxis run on compressed natural gas (CNG) (McKinsey, 2009b). Figure 10 suggests that demand from the transportation sector is expected to almost double between 2005 and 2015 and again between 2015 and 2030.

Fig. 10. China's Transport Sector Gas Consumption Break-down



Source: IEA, 2007

2.3. Market Characteristics

China's wholesale and retail gas market is dominated by the three majority state-owned oil companies: China's National Petroleum Corporation (CNPC: 中石油), China's National Petroleum and Chemical Corporation (Sinopec: 中国石化) and China's National Overseas and Offshore Corporation (CNOOC: 中海油). CNPC is the largest of the three with around 75% control of domestic gas resources and an 80% holding of the pipeline network. In addition, CNPC is responsible for the Central Asia-China pipeline project. As its title suggests, CNOOC was set up to manage off-shore oil and gas resources and is the leading LNG company. In contrast, Sinopec has traditionally been an oil company with only a 10% share of gas production. In 2008, the company produced around 8.3 bcm of mainly from gas fields in Sichuan and Shandong. While the three companies are majority state-owned each control subsidiary companies that include private shareholdings and are consolidating their control of the natural gas sector through vertical integration.

In contrast, the residential gas sector is local government owned. Retailers at the city level purchase from big three. There is some private investment in terminals and residential market, including overseas investment.

While there does not appear to be much discussion about changing the current wholesale gas monopoly in China, already some shifts have occurred in terms of vertical integration and regional spread. Previously, the three leading gas companies operated regionally, but there are growing signs of increasing competition across regions but largely contained to the three gas majors. For example, CNOOC previously monopolised LNG but in recent years CNPC and Sinopec have started to invest in this area. Some industry analysts suggest that the three-majors monopoly is impeding the development of the natural gas sector; calling for the breaking up of their monopolies and greater competition (Dai, 2010). Market reforms are currently taking place that are reshaping the gas market in China and are discussed in the policy section of this report.

The coal seam methane market is less dominated by the big three with a growing number of smaller private outfits as well as some of the coal industry groups showing an interest. Currently, the Chinese government requires all foreign companies to work with the government's CUCBM. The CUCBM provides regulatory support with template contracts, assist companies in locating contractors and in gaining official clearance from various government departments. There are however, a large number of emerging private companies, including in the coal seam methane sector. Xinxing Natural Gas is one example of a company outside of the big three, which is involved in retail and wholesale gas supplies. Some commentators have noted the presence of tension between the gas and coal industry in the development of CBM. However, in recent years there have been several mergers between CNPC and coal companies for developing CBM. In the short-term these mergers have often been unsuccessful.

Pricing

The pricing of gas in China is currently in a period of reform as the government gradually moves towards a market based pricing system to facilitate the development of national and regional gas markets, increasing demand for gas across all sectors and the growing reliance upon imported LNG supplies. The current experience with gas price determination and outcomes in China can be described as follows:

- Historically China has adopted an accounting cost plus approach for gas based on extraction and distribution costs, and reflecting a controlled economy philosophy. However, this is slowly changing with increasing receptiveness to market principles.

- Natural gas prices have also been historically controlled due to fertilizer industry quotas and subsidised prices – used for both fuel and feedstock.

- General reforms have flown through more recently (getting prices closer to international levels), but control is still maintained, and city-gate prices vary by sector and location with industry paying the highest, followed by residential, the power generators and then fertilizer production.

- Average city-gate gas prices are:

  - fertilizer producers: US$2.70/MMBtu;

- o industrial users vary from US$11.02/MMBtu in Shanghai to US$4.75 in Lanzhou; and
- o residential users: US$5.85/MMBtu in Beijing and US$4.71 in Zhengzhou.

Currently, gas pricing schedules for chemical, commercial and residential sectors are set by the NDRC, whereas wholesale to retail schedule prices are set by local governments (Figure 11). In general, residential prices are lower than other users with the government providing a subsidy to retailers.

Prices vary considerably between source, regions, industry sector, wholesale and retail.[8] For example, a March 2010 report (China Business, 2010) found that prices varied from a low of RMB1.63 per cubic metre to a high of RMB3.85 per cubic metre. The cheapest gas came from the Zhongyuan Field and was supplied to Dapeng in Guangdong. In contrast, shipped LNG from Qatar is expected to cost around RMB3.5. Retail residential prices in the key southern industrial cities of Guangzhou, Foshan and Dongguan pay RMB3.45, RMB3.85 and RMB3.6 per cubic meter because of their proximity to low-priced LNG from Australia. The same report estimated the second west-east pipeline will result in wholesale gate prices in southern Chinese cities of around RMB3 per cubic meter, which is around double existing prices.

Relatively low natural gas prices at the beginning of the century resulted in many coastal cities embracing the fuel as a solution to its unsustainable reliance upon polluting coal. These coastal cities set in train energy policies with an increasing reliance on the cleaner gas. However, due to the rise in gas prices between 2004 and 2007 and central government limitations on its use (see later discussion), many of the cities needed to recalibrate their energy policies.[9] The combination of central government policies and high gas prices also resulted in slow progress in the approval of and commencement of construction of new LNG port terminals and a lull in new contracts to supply the terminals.[10]

The gradual pace of China’s resource and energy price reforms in moving away from the existing capped well-head price to a market price aligned with global benchmarks is apparently slowing investment in CBM exploration and development (Chen Aizhu, 2010).[11] China's domestic natural gas well-head price ($3.5-$4.0/MMBtu) remains a third below China's imported LNG costs.

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[8] In the second quarter of 2010, reforms to the energy and resource pricing systems including further raising the cost of electricity, oil and gas, are expected (State Council, 2010). Upward pricing adjustments are more likely whilst inflation pressures remain low, due to sensitivity about negative social implications to the cost of living. In May 2010, natural gas pipeline transmission fees were increased slightly in the south west of China in an effort to curtail the large amount of fertiliser production occurring in the region, much of which is exported.

[9] The cost of imported gas doubled between 2004 and 2006 so that in some areas gas was four times the price of coal. However, in coastal cities the difference was much less with some even encountering parity.

[10] LNG port terminals in Fujian, Shanghai and Ningbo were all delayed due to disputes over the price of imported gas.

[11] For example, this report cited the case of Chevron relinquishing its interests in its three Chinese-based CBM production sharing contracts in 2009. While the reasons were not disclosed, analysts noted that a combination of institutional barriers, cost issues and the low price of gas would have contributed.

In 2010, the State Council proposed a new natural resources tax that will increase the amount of revenue raised by local government from natural resource extraction (Wang, 2010). Currently, all revenue from natural resources (with the exception of offshore resource taxes) goes to local governments. The new proposal includes a 5% levy on oil and gas prices, rather than volume and is estimated to increase taxes from oil revenues from the 2009 figure of RMB5.3 billion to RMB47.3 billion alone. The introduction of such a tax will increase downstream costs of domestic gas, but it may increase the incentives for local governments in developing coal seam methane reserves. Presently, local government revenues from coal mining are much higher than gas, which is seen as of little local benefit (Ng, 2009). The new tax may adjust the imbalances in incentives at the local level.

The ongoing discrepancy between the domestic and imported gas prices as well as between sectors was blamed for the shortage in gas supplies during the 2009-2010 winter apparently due to oil utilities trying to increase pressure on the central government to increase retail prices (Chen & Zhang, 2010).[12] The gas shortage was estimated at around 20 bcm in 2009 with predictions it could even rise to 90 bcm by 2020 (Zhai, 2009). Since late 2008, China has instituted a flexible domestic fuel price system reflecting the average of a basket (Brent, Dubai and Cinta) of crude oil prices over 22 days. If gas prices shift by more than 4% during this period then the domestic price is adjusted. For example, in November 2009, the NDRC increased the non-residential electricity tariff RMB0.028 cents per kilowatt hour and raised gasoline and diesel prices by 7%. The ten adjustments by the NDRC since the system commenced to April 2010 have included six rises and four declines with each shift balanced against any inflation risks. The latest move was in April 2010 when fuel and diesel prices rose 4% and 4.5% respectively with a less than 0.1% predicted impact upon monthly inflation (Caixin, 2010).

3. Current Natural Gas Policies in China

Natural gas is considered an important part of China's future energy mix in order to provide greater energy security through diversification, achieve energy efficiency gains in industry, reduce air pollution and decrease the nation's carbon intensity. Many of the government's key energy policies during the past five years have elevated the status of natural gas vis-à-vis coal and oil for industrial use, heating and power generation.[13] The strong economic growth of the past decade has stressed China's energy resources sector, including the supply of natural gas. In response, the government has promoted the extraction, development, distribution and utilisation of natural gas at a domestic level. In addition, the government has encouraged Chinese oil and gas companies to expand their investments in gas overseas. To balance the rising gas imports with expanding domestic demand, government reforms are reshaping the gas market, pricing, regulations, policies and the key players.

The Chinese government has been promoting natural gas use in order to improve energy diversification and energy efficiency, and as a solution to environmental problems. Under the 10th Five-Year Plan (2001-05), the government set the target of raising natural gas use to 10% of the

[12] From November 2009 through to March 2010, many utilities and cities were forced to ration gas supplies to commercial and transport users so as to guarantee residential heating.

[13] The 2004 *National Energy policy and Strategy* supported the expansion of natural gas especially in the residential and power generation sectors.

energy mix in 2020, which was basically reiterated in the 11th Five-Year Plan (2006-10). As part of the national 11th Five-Year Plan (2006-2010), the government aims to cut energy use per unit of GDP by 20% and pollution by 10% by 2010.[14] Increasing the supply and consumption of natural gas was seen as playing an important role in contributing to these goals. However, the rising price of gas in 2007-2008 combined with strong local demand, resulted in the central government tempering its support for gas.

In order to resolve supply and demand issues, in 2007 the National Development Reform Commission introduced the 'Natural Gas Utilisation Policy'. The policy prioritised natural gas use for residential purposes, forbid natural gas development for methanol use or in areas with large-scale coal bases and maintained subsidised natural gas for fertiliser production. Current Government plans aim to double gas production to around 160 bcm by 2015 and 250 bcm by 2020 (equivalent to 10% of primary energy consumption). The global situation with natural gas is changing rapidly, in ways that might support a major, long-term expansion of natural gas use in China. For instance, there are large potential supplies of low-cost conventional natural gas and coal seam methane (CSM) resources available for development both domestically in China and globally. In the longer term (beyond 2013-14) gas prices are likely to fall relative to oil, reflecting the quite different supply positions of the two fuels.

In a further repositing of natural gas, the central government trialled a new electricity discharge or scheduling system which ranked natural gas below some coal-powered generation. Under the 2007 trial system, which was implemented nationally in 2009, power would need to be first purchased from low carbon sources of energy generation (wind, solar, hydro and nuclear) before coal and gas. Gas powered plants, including coal seam methane plants and coal-gasification are grouped together.[15] Higher efficiency gas and coal cogeneration plants are similarly grouped together, but importantly above coal fired generation. While the scheduling system does not promote gas-powered generation per se, it should strengthen investment in gas powered generation. Under the scheduling hierarchy gas is offered greater certainty with higher dispatch rates, which is an important criterion for plant profitability. Currently, dispatch rates amongst gas powered plants remain low, with most plants supplying peak loading power.

The National Development and Reform Commission (NDRC) is responsible for gas polices as well as wholesale price setting, while the provincial and municipal governments are responsible for local gas policies relating to supplies, distribution network and final price settings. This allows local governments to manage their own energy mix as is appropriate to local conditions. As a result, national policies try and avoid being too prescriptive to accommodate regional differences. The main driver for the expansion of natural gas from a policy perspective remains energy security. Yet, at the same time, environmental considerations are also a factor due to natural gas' lower carbon and pollutant emissions. See the separate CSES (2010) report "The transition to a low carbon economy:

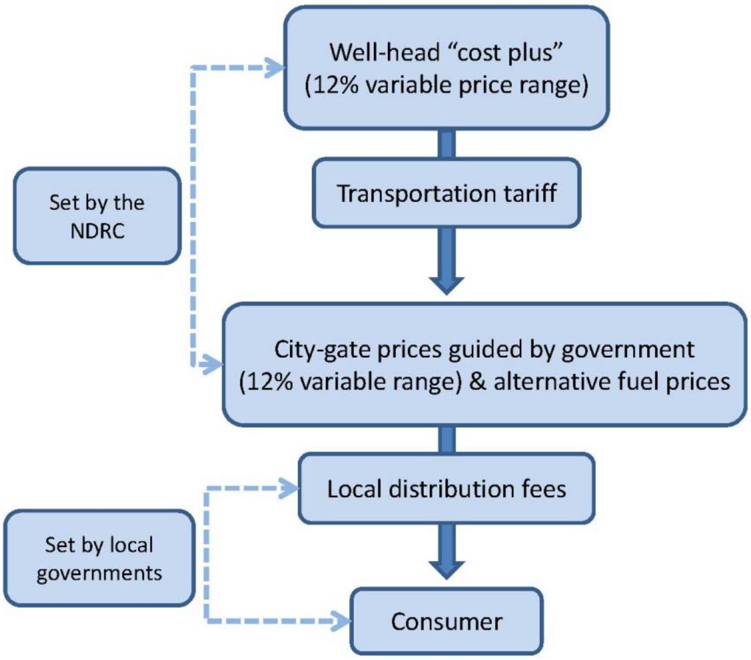
[14] This goal will most likely be adopted in the forthcoming 12th FYP (2011-2015).

[15] While natural gas are clustered together with CBM and CMM in the power scheduling hierarchy, the latter two receive value added tax rebates and state subsidies for the exploration and development of fields. Such government financial and taxation subsidies amounted to 33% of the sale price of CBM (Ng, 2009).

implementation issues and constraints within China's changing economic structure" for full policy details including discussion of China's 2007 National Action Plan on Climate Change.

There are a broad range of government policies that shape the demand and supply of natural gas in China. For instance, the recent growth in gas consumption has been caused by a combination of government-led market reforms in the coal industry; a significant expansion of natural gas infrastructure; environmental regulations demanding greater efficiency in the energy-mix; a partial closing of the price-gap between coal and gas; and, longer lead-times for alternative primary energy technologies.

Fig. 11. China Cost-Plus Natural Gas Pricing System



Source: Ni, 2007; IEA, 2009b

China's gas price-setting has been reviewed relatively recently, but is still based on a tiered system, where fertilizer makers receive a subsidised price, then the residential sector followed by commercial enterprises.[16] The existing price system has three components (Figure 11):

(A) Ex-Plant Price: determined principally on the production cost of natural gas (wellhead cost plus purification fee, including financing cost and tax) plus the appropriate margin for producers (IRR 12%).

(B) Transport Tariff: determined based on the pipeline cost (construction and operation) plus the appropriate margin (IRR 12%) with the variation of transport distance from each gas source to each city gate. The city gate price is (A) + (B); and,

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[16] A decade ago, the gas industry received the largest state subsidies for energy generation, however these have been reduced substantially from around US$23 billion in 1998 down to less than US$2 billion in 2005 (IEA 2007).

(C) Final price, as determined by the Provincial Governments by taking into account the distribution cost, alternative fuel prices and other market policy factors.

Limitations on the expansion of the natural gas sector

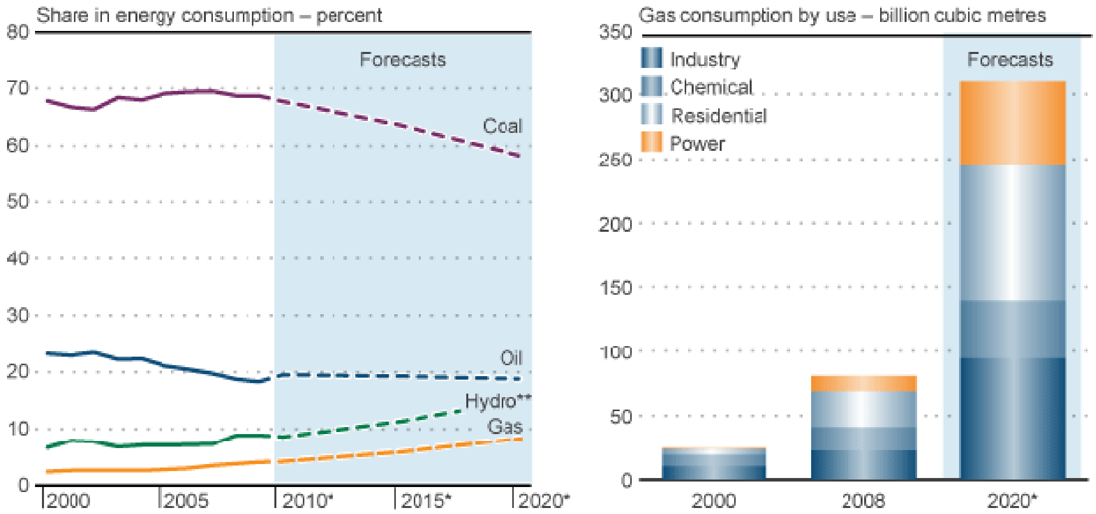
In 2006, the Energy Research Institute together with the Power Economic Research Center of the State Grid Corporation of China completed a major report on the role of the natural gas industry in China's economy and specifically about the role of gas-fired power generation in providing the impetus for the broader development of the industry (ERI 2006). The report concluded that, on both security of supply and environmental grounds, developing a substantial natural gas industry was very much in China's interests, and that a number of major gas-fired power projects would provide a critical boost for wider industry growth. But they concluded that many matters needed to be addressed if gas-fired electricity generation were to be competitive with coal, in the context of the developing competitive market for electricity and the high price of gas on world markets relative to the price for coal in China. The report made a wide range of recommendations, both for appropriate market-based arrangements for determining the on-grid tariff for gas-fired power plants and the gas price for power generation, together with methods for closing the gap between the net-back price from the on-grid tariff and the factory gate price. These methods include local authority subsidies and improved tax and tariff treatment for gas exploration, pipeline operation, LNG imports and gas-fired power generation.[17]

4. Projected Demand for Natural Gas

As discussed in earlier sections, China's demand for natural gas has risen steadily during the past decade and accelerated during the last few years. Moreover, gas consumption is spreading geographically from a traditional concentration around local gas fields towards coastal cities, especially the Yangtze River and Pearl River deltas due to increasing residential and power sector demand. The two diagrams in Figure 12 provide some context to this expansion by showing how the share of gas remains small in China's total energy mix, yet the expected growth in actual consumption is strong. By 2020, some industry analysts expect China's consumption of natural gas to exceed 300 bcm with consumption roughly divided between residential (34%), industrial (30%), power (21%) and chemical (15%) users (Figure 12).

[17] A further constraint on the development of natural gas is its exclusion from the eight core coal production areas. It is unclear how this policy affects the development of CBM opportunities, which is already impeded by 'overlapping mining rights between coal and gas miners' and uncertain government policy (Ng, 2009). While there has been a recent increase in the number of private and state companies exploiting CBM, the disappointing extracting rates belie initial optimistic government projections for its growth.

Fig. 12. China's Energy Mix, 2000-2020

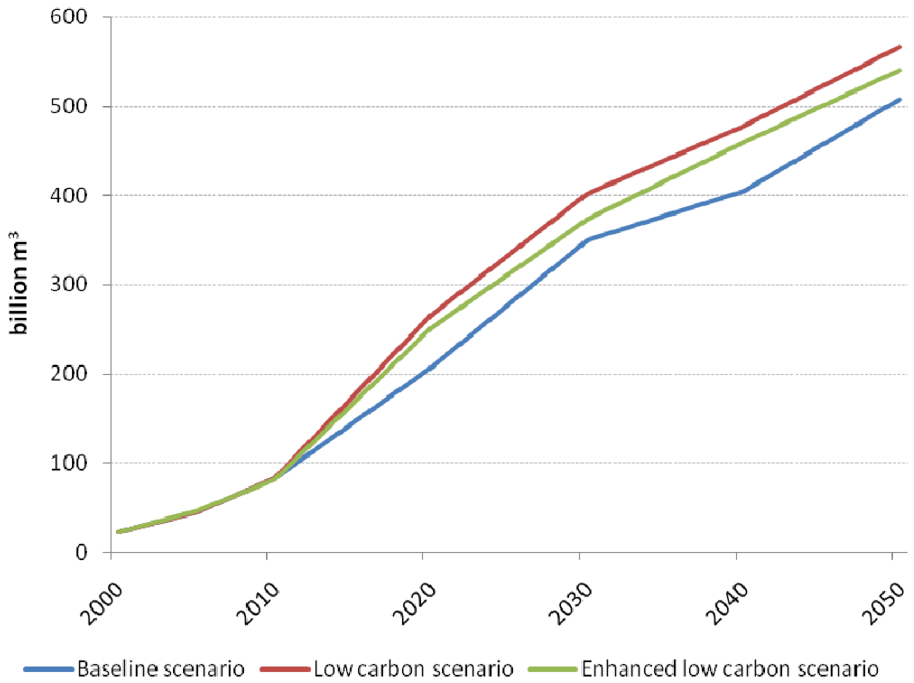


Note: * forecasts, ** hydro and renewables.
Source: NBSC, Bernstein Research and CNPC data in Reuters (2010) China's Energy Mix – the Rising Share of Gas, 17 March, online: http://graphics.thomsonreuters.com/310/CN_GS0310.gif

The future for natural gas in China is mixed. On the one hand increasing carbon constraints and taxes will increase its price. On the other hand, technological and pricing shifts will open up significant new domestic resources of gas, especially from coal seam methane in the short-term and coal gasification and methane hydrates in the medium to long term. According to estimates by the IEA's *2009 World Energy Outlook* and the EIA's *World Energy Projections 2009* reference case, natural gas consumption rises rapidly in China by more than five percent per year on average from 2007 to 2030.[18] The EIA and IEA estimates would lift gas demand to around 242 bcm respectively. This is a very conservative estimate. McKinsey (2009a) expect China's gas consumption to increase eight times between 2007 and 2030 to reach 420 bcm while Royal Dutch Shell (2010) expects gas demand to be between 200-300 bcm by 2020. A similar estimate is provided by CNPC (2009) of around 255.5 bcm by 2020 with domestic production exceeding 200 bcm and unconventional gas supplying 30% of total production. Either way, the expansion of gas demand in China will be a two-sided experience with rising demand driven by steady population growth, urbanisation, rising living standards and industrialisation as well as strong growth in the development of domestic reserves of gas, including so-called 'unconventional' supplies of CBM.

[18] The IEA (2008) estimated natural gas consumption in China would reach 108 bcm in 2015, surpassing Japan as the top gas user in the Asia Pacific. However, the rapid growth of gas consumption in China and the recent decline in the Japanese economy should see China eclipse Japan in 2011. In 2009, Japan consumed 94.68 bcm of mostly imported LNG.

Fig. 13. Primary Energy Demand Using Natural Gas, IPAC-AIM Technology Model

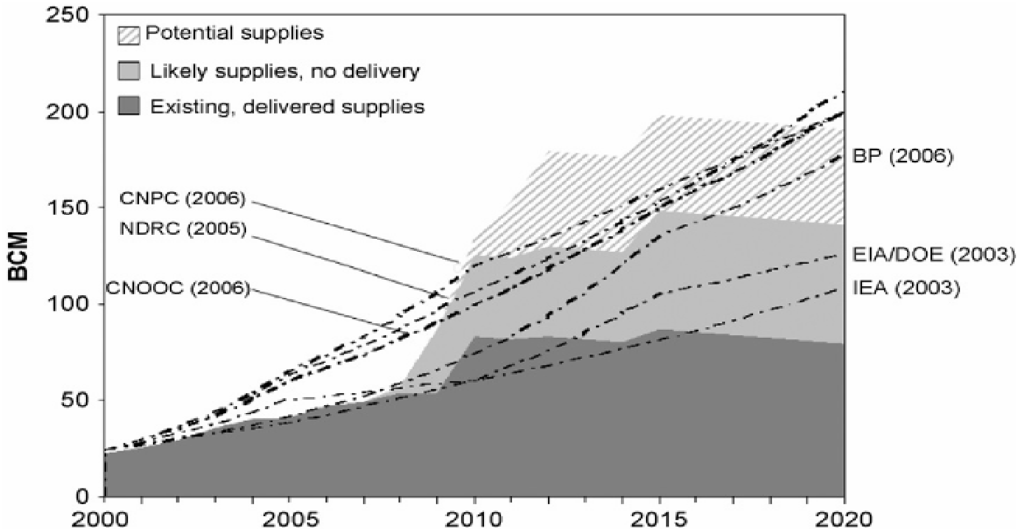


Note: Conversion estimate based upon 1 million metric tonnes of standard coal = 0.761 bcm (NRC et al., 2000)
Source: CEACER, 2009

According to ERI analysis (CEACER, 2009), future natural gas demand will vary depending upon the policy setting. A baseline policy scenario will lift gas demand from the current 83 bcm in 2010 to 206 bcm by 2020, 350 bcm in 2030 and 508 bcm in 2050 (Figure 13). In contrast, if China was to adopt policies commensurate with a low carbon economy then these figures would increase to 266, 403 and 567 bcm respectively in 2020, 2030 and 2050. Under an enhanced low carbon scenario the demand for natural gas would be somewhat slower due to higher energy efficiency gains and a greater presence of renewable, nuclear and CCS. While the ERI figures remain conservative, they do show that regardless of the national policy setting, the forecast for natural gas through to 2050 will be similar.

Due to China's limited conventional reserves of natural gas (Figure 14), China is accelerating the expansion of CBM reserve development, building more LNG terminals and continuing to enlargen the national network of pipelines to tap into local and international gas deposits for industrial purposes, to power newly built cogeneration natural gas power stations, for domestic and commercial building heating and to power local bus and taxi fleets.

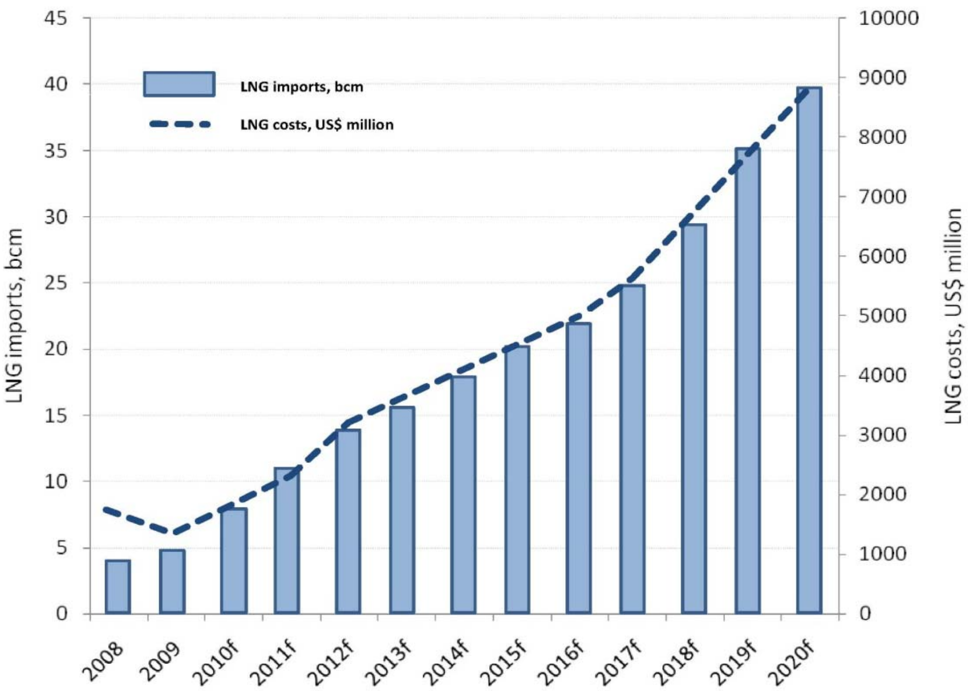
Fig. 14. Potential Natural Gas Supplies and National Demand Projections, China



Source: PESD estimates 2007, CNPC/Sinopec/CNOOC company reports 2007, ERI, IEA 2004, Chinese agencies: NDRC, China Energy Development Report 2003, CNPC, CNOOC Western sources: BP, EIA/DOE 2003, AIE/WEO 2002 cited in Jiang et al., 2008

Figure 14 highlights the gap between domestic supplies and demand for natural gas between 2000 and 2010, but also the need for greater investment in new supplies after 2020. Domestic gas production will increasingly yield market share to imports with at least 24 bcm of LNG and up to 40 bcm of Central Asian pipeline gas annually from 2011 (Higashi, 2009; Lin et al., *in press*).

Fig. 15. Estimated LNG imports and costs for China

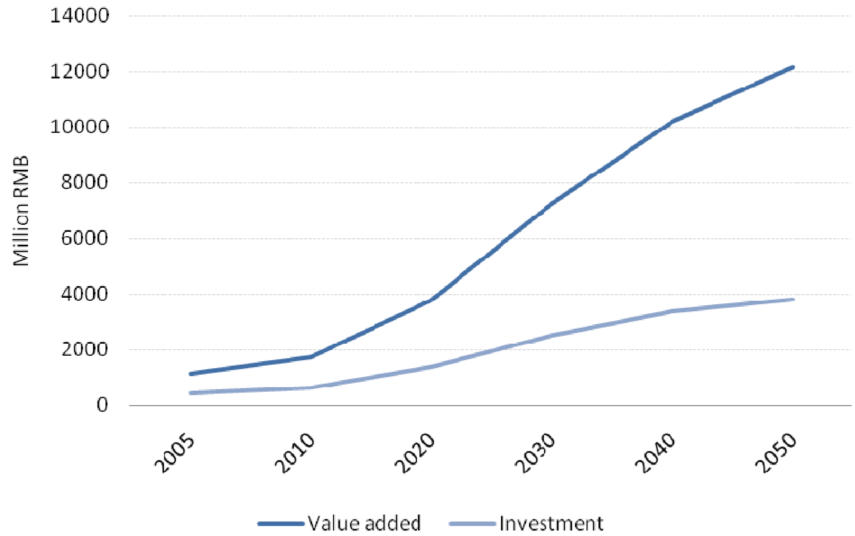


Note: *f* BMI estimates only.
Source: BMI, 2009

In terms of imports, Business Monitor International (BMI) estimates Chinese LNG imports will increase from 4.4 bcm in 2008 to 16 bcm by 2013 and around 40 bcm by 2020 (Figure 15). In 2009, China imported around 5 bcm of LNG, which was equivalent to around 6% of total natural gas consumption. So far, China has already signed agreements for the supply of up to 33 bcm from 2011. A figure that is likely to double by 2020. BMI estimate LNG costs to remain relatively stable through to 2020 with a slight drop in costs relative to volume of around 20% from around US$2 billion in 2010 to nearly $9 billion annually by 2020.

According to ERI's (CEACER, 2009) modelling, the economic benefits of an expansion in natural gas will steadily increase as it shifts away from low value added fertiliser and industrial use and is instead supplied into higher value added production. The results from a business as usual scenario of value added and investment in the natural gas development, extraction and processing industry shows that investment will reach RMB2 billion annually by 2025 and double by 2050 (Figure 16). The benefits of investment in the gas sector will multiply with a growing divide between investment and value added, especially after 2020.

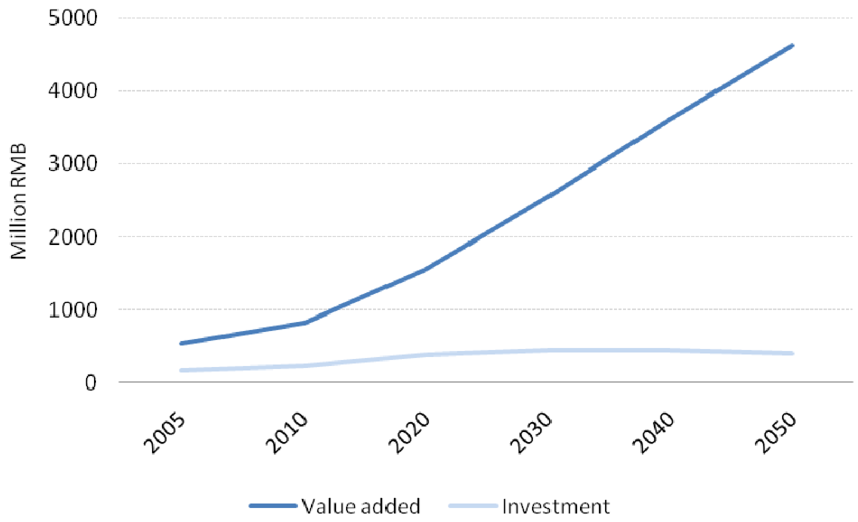
Fig. 16. Value Added and Investment in the Natural Gas Development, Extraction and Processing Industry under Business as Usual Scenario



Source: CEACER, 2009

As discussed earlier in this report, investment and value added in the CBM sector has been relatively slow. CNPC forecast CBM and shale gas could supply about 15% of China's 2020 target of 200 bcm natural gas usage (Chen Aizhu, 2010). ERI (CEACER, 2009) analysis suggest that while investment levels will remain low through to 2050, the economic benefits of coal gas will grow almost ten times between 2005 and 2050 when they exceed RMB4.6 billion (Figure 17).

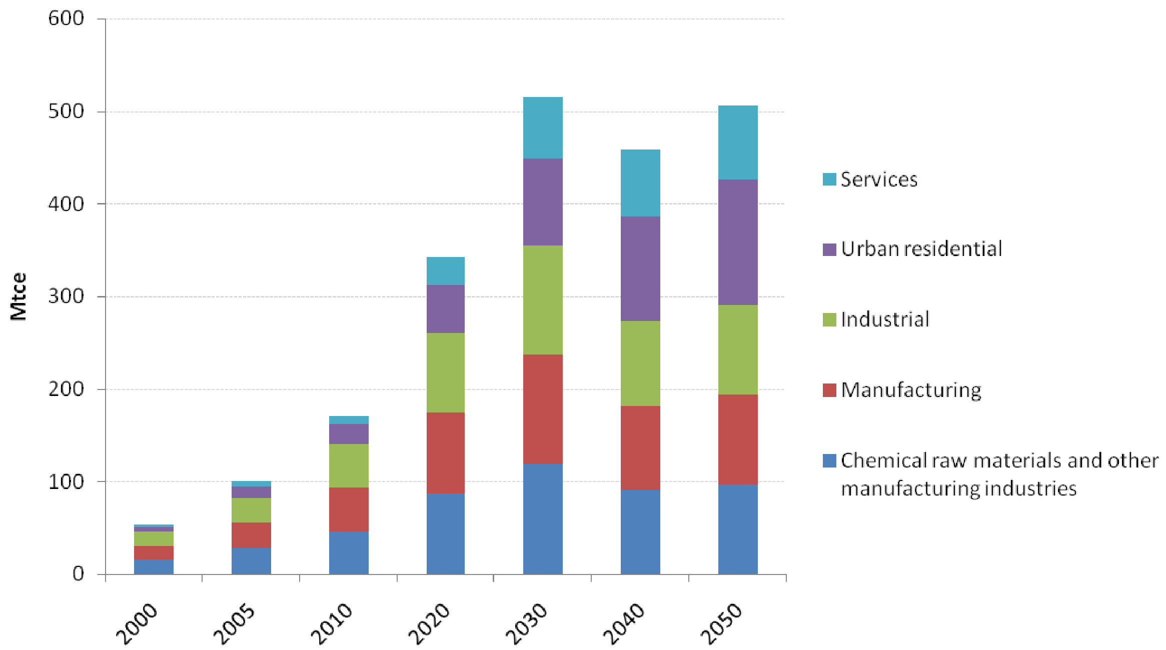
Fig. 17. Value Added and Investment in the Coal Gas Supply and Production under Business as Usual Scenario



Source: CEACER, 2009

ERI analysis of the key sector demands for natural gas under the baseline scenario reveal a surge in overall gas demand between 2010 and 2020 with all sectors experiencing a doubling of demand (Figure 18). The gas market will continue to be dominated by industrial, manufacturing and chemical sector demand. However, demand from these sectors will then peak and decline by around 20% by 2040 and then begin to slowly expand through to 2050. As a result, urban residential demand for gas will surpass each of these sectors by 2035 to exceed 100 bcm by 2050. Service sector demand for gas is estimated to steadily rise from 7 bcm in 2010 to 60 bcm in 2050.

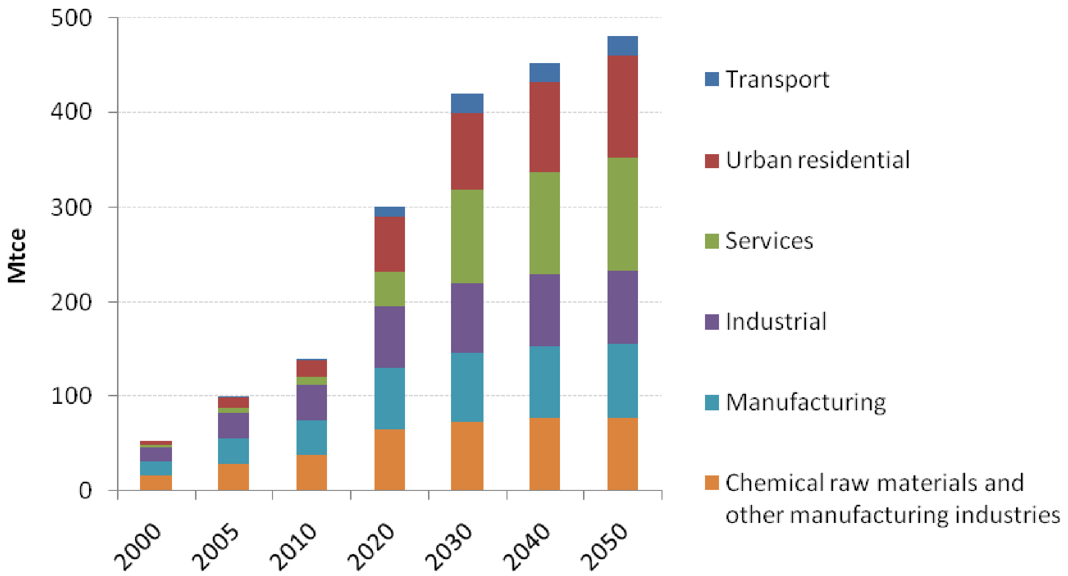
Fig. 18. Terminal Natural Gas Energy Demand by Sector (Mtce) Baseline Scenario (IPAC-AIM Technology Model)



Source: CEACER, 2009

Under a low carbon scenario (Figure 19), gas demand is expected to experience equally strong growth, especially between 2010 and 2030. However, in contrast to the baseline scenario, the services and urban residential sectors will be the main drivers for future gas demand, surpassing demand in the industrial, manufacturing and chemical industries, which will experience slower growth after 2020 and then reach a plateau in 2030. Overall gas demand growth will be slower to 2030, but is expected to reach comparable levels with the baseline scenario by 2050. The transport sector makes an appearance under the low carbon scenario between 2020 and 2030 due to the higher penetration and usage rates of gas-powered public transport.

Fig. 19. Terminal Natural Gas Energy Demand by Sector (Mtce) Low Carbon Scenario (IPAC-AIM Technology Model)



Source: CEACER, 2009

Regardless of the policy outcome China follows in the next decade and thereafter, natural gas is likely to play an increasing role in the nation's energy mix. However, as this section has discussed the dominant position of domestic gas production vis-a-vis imported gas is shifting quite quickly. Therefore, in order to satisfy expanding demand, China has adopted a gas diversification policy to expand local production whilst exploring overseas supplies.

5. Diversifying Gas Supplies

5.1. Introduction

China is entering a period of significant growth in gas demand. In response, dozens of major gas projects are either underway or will be completed by 2015, including, construction of gas infrastructure, the exploration and development of new fields and signing of international supply contracts. China currently imports LNG from Australia, Indonesia, Malaysia, Qatar and Iran with piped natural gas sourced from Turkmenistan with future supplies coming from Kazakhstan, Uzbekistan, Myanmar, Mongolia and Russia.

Fig. 20. Imports of Natural Gas, 2009

	Imports		Rate of changed compared with 2008, %	
	bcm	US$ million	Volume	Value
Natural gas & synthetic gas	5.53	1 279.5	65.8	35.5

Source: Customs Statistics, 2009

In 2009, imported natural gas increased to 5.53 bcm of gas costing nearly US$1.3 billion, which equates to growth of 65.8% by volume and 35.5% by value compared with 2008 figures (Figure 20). It is predicted that by 2015, gas imports shall exceed 40 bcm with the west to east pipeline bringing in 30 bcm and coastal LNG facilities handling more than 10 bcm. The Myanmar pipeline should also be operational with a capacity of up to 12 bcm of gas annually. At the same time, new domestic gas pipelines connecting the Sichuan basin with Shanghai, the Ordos basin with Beijing and the second West-East line will double existing pipeline capacity. Large storage facilities are being built in eastern coast cities and also at strategic points along the west-east trunk lines.

On the domestic front, PetroChina and rival Sinopec Corp are developing new, big fields such as Dina and Tazhong in northwest Xinjiang; Sulige in Inner Mongolia; Longgang and Puguang in southwest Sichuan, while fast-tracking explorations by adding 200 bcm of incremental recoverable reserve each year. Locally-based natural gas utilisation will grow significantly in China over the next decade as local governments and industry seek out diversified cleaner, low cost energy sources.[19]

Internationally, the start of long-term gas deliveries from Qatar, Indonesia and Malaysia will double imports of liquefied natural gas by 2011. These will surge even further in coming years, after firms such as Qatargas, Shell, BP and Exxon Mobil recently sealed supply pacts with Chinese firms worth over $100 billion. In May 2010, China and Qatari officials were negotiating the supply of a further 10 million tonnes of LNG on top of the existing 5 million tonnes (England, 2010). Several new LNG terminals, in addition to the existing three, will be supplied by new long-term supply contracts with Malaysia, Indonesia and Qatar. A further 5 bcm per annum will come from Australia’s east coast CBM fields, 4.4 bcm from the North West Shelf (Browse) and rising a further 6.2 bcm and 2.7-4 bcm respectively once the Gorgon and Woodside Browse projects commence. By 2015, piped gas from Turkmenistan and Myanmar will together amount to 20 percent of China's demand, or 40 bcm. Russian gas may then follow with a further 70 bcm annually, but a high degree of uncertainty remains about a starting date.

5.2. Gas Infrastructure

For the past decade China has embarked upon an ambitious program of transforming its natural gas industry from a provider of small-scale fertiliser feedstock based upon local supplies to an important

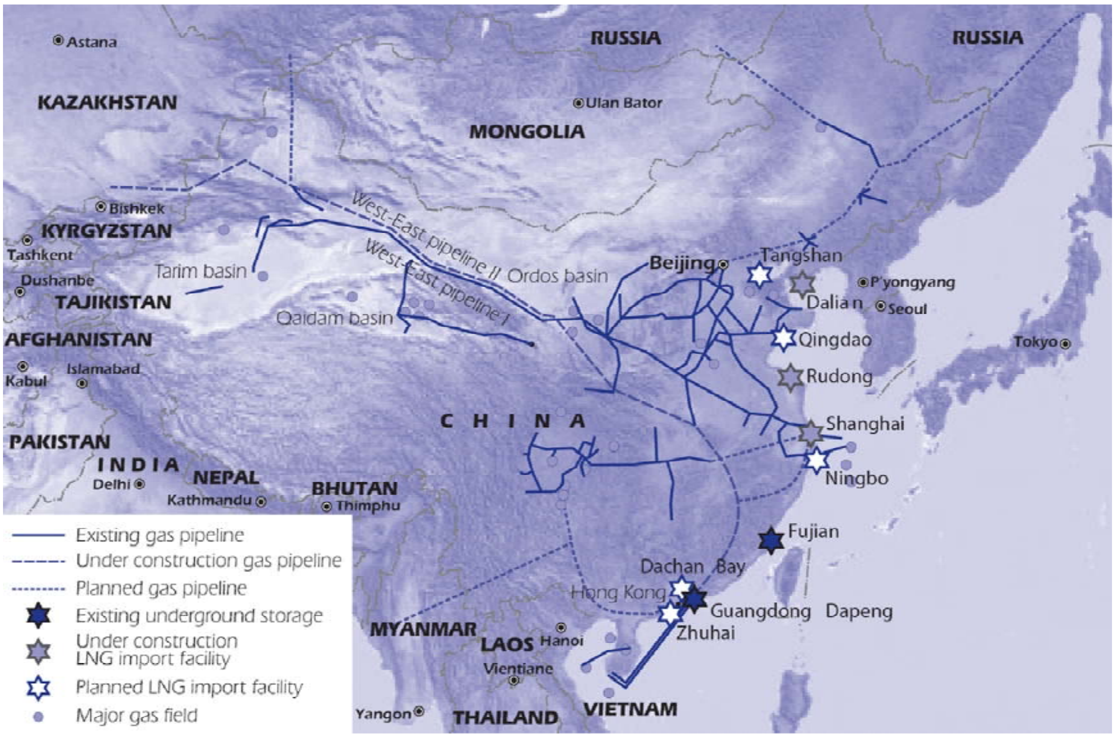
[19] Against a backdrop of an expanding national gas pipeline network, several cities are exploiting local gas deposits. For example, the city of Da'an, in Jilin province has access to natural gas deposits of around 2 billion cubic meters and will build a 100 MW cogeneration power-heat plant in the city.

international gas market player. To facilitate this transition, China is building up both domestic and international gas infrastructure, including new and expanded pipelines across the country and into neighbouring countries, new LNG terminals are along the east coast alongside liquefaction and regasification plants and the sinking of thousands of new gas wells tapping into CBM supplies. The scale and speed of natural gas developments in China are of an unprecedented magnitude. In order to facilitate this investment in gas energy supply infrastructure the IEA (2009a) estimates US$233 billion will need to be spent annually between 2008 and 2030. This is equivalent to around 5.5% of current total energy supply spending.[20]

Transboundary and Domestic Pipelines

Figure 21 illustrates the growing network of pipelines connecting up China's dispersed gas fields and LNG ports and new transboundary supplies. In 2004, China completed its first 3,900 km West-East domestic gas pipeline connecting fields in western China to coastal cities. This pipeline marked the

Fig. 21. Natural Gas Infrastructure, China



Source: IEA, 2009b, 127

country's transition from local gas supplies to a national natural gas market. Three earlier pipelines included the 868km Ordos to Beijing connection and the two ocean pipelines connecting the off-shore fields of Yacheng and Pinghu with Hong Kong and Shanghai respectively. By the end of 2008, a total of 31,000 km of pipes had been laid across China.

[20] The IEA estimate includes new gas energy capacity covering production, transportation and transformation as well as unit capital costs for gas throughout the supply chain.

Between 2009 to 2015, the state plans to double its gas pipeline infrastructure with a further 48,000 km of pipelines, including 24,000 km of trunk lines. For example, a third West-East gas pipeline will stretch from Xinjiang to Guangdong and run through Gansu, Ningxia, Shaanxi, Henan, Hubei, Hunan. The pipeline is estimated to commence operations in 2014 with a capacity of 30 bcm annually, which will bring total west to east pipeline capacity to 60 bcm.[21] Additional distribution capacity includes a 1,660 km long gas pipeline from the Sichuan gas fields to Shanghai, Jiangsu and Zhejiang provinces and a 1,000 km pipeline connecting Shandong's gas fields with the wealthy coastal ports of Qingdao and Weihai. Since 2009, China has commenced the next stage of gas development: from domestic supplies to an increasing dependence upon imported gas. This includes pipeline gas from Central Asia (notably Turkmenistan and Kazakhstan), Myanmar, Russia and Mongolia and LNG shipped from Qatar, Malaysia, Indonesia, Iran, Papua New Guinea and Australia.

In January 2010, the western section of the second West-East pipeline was completed facilitating the transmission of gas from Turkmenistan through central Uzbekistan and southern Kazakhstan to Xinjiang province. Gas from Turkmenistan is expected to provided 6 bcm of natural gas in 2010 gradually rising to 40 bcm annually by 2040 (Asia Pulse, 2010). The pipeline is the first to facilitate trans-boundary gas flows into China, which then connect to the domestic West-East pipeline, which traverses 8,653 km through 14 provinces before reaching Guangdong in the south. A further 4,843 km second-stage through to Guangdong with a capacity of 30 bcm per annum will be completed in 2012 (China Business, 2009). Both stages will collectively serve a large number of provinces with both domestic and imported gas. PetroChina is currently in negotiations with Turkmenistan, Kazakhstan and Uzbekistan for the construction of a further two Central Asian feed-lines to supply China's three West-East lines (China Business, 2009).

A further international transboundary pipeline is under construction between Myanmar and China. The 870-km long pipeline built by CNPC will transport gas from Myanmar's off-shore fields, which are being developed by a Korean-led consortium of Chinese, Indian and Myanmar interests. An oil pipeline is being laid next to the gas pipeline to transfer oil shipped from Africa and the Middle East to Myanmar so as to avoid the Malacca Straits. Both pipelines will connect to domestic pipelines feeding Yunnan Province from 2014 and the southern cities of Chongqing and Nanning.

LNG Port Facilities

China's ascendancy as a major LNG buyer has been rapid with the signing of several long-term supply and purchase agreements (SPAs) as well as initial agreements in the past five years (Figures 22 and 23). China's current share of the LNG market is around 2% but is expected to grow to 13% by 2020 (Morikawa, 2008). Although CNOOC dominates the LNG import market in China, CNPC and Sinopec are diversifying their interests and regional coverage by entering the LNG market. China currently has three LNG terminals in operation in Shenzhen, Fujian and Shanghai with a total capacity of 9.3 bcm annually. According to Figures 22 and 23, China is expected have a total 30 mBtu of LNG import capacity by 2015. In addition to coastal LNG facilities, approval was granted in 2010 for the construction of several new LNG stations in inland cities, for example in the Yangtze River cities of Wuhan, Yichang, Xiangfan and Huangshi. The gas would be used to meet growing demand from residential, industrial and transport users in the cities.

[21] However, to date only half of the supplies have been agreed upon leaving a possible 30 bcm shortfall.

Fig. 22. LNG Receiving Terminals including Sale and Purchase Agreements, capacity in million tonnes per year

LNG TERMINAL	STAGE	CAPACITY	STAGES	STAKEHOLDERS	AGREEMENT DETAILS
Shenzhen	Operation	3.7	Phase I 2006	CNOOC 33,% BP 30%	(i.) North West Shelf LNG Australia (Browse)25-year US$13.75 billion at US$3.16 per mBtu with price reports as low as US$2.50-US$2.70 per mBtu; (ii) Qatargas Operating Co. Qatar (Qatargas 2) 25-year MOU negotiated at market value; (iii) Total Gas & Power sourced from Total's global LNG portfolio 15-year; (iv) ExxonMobil Australia (Gorgon) US$41.1 billion 20-year agreement at US$10 per mBtu
	Construction	6.6	Phase II2011	CNOOC	
Fujian	Operation	2.6	Phase I2009	CNOOC 56%	(i) BP Migas Indonesia (Tangguh) 25-year US$2.40 per mBtu under old contract signed in 2002 and revised to US$3.80 per mBtu, then US$4.54 per mBtu under SPA in 2006, and finally US$5.93 per mBtu in 2008.
	Construction	5	Phase II2012	CNOOC	
Shanghai	Operation	3	Phase I2009	CNOOC 45%, Shenergy 55%	(i) Malaysia LNG Tiga25-year US$25 billion deal at $5-US$7 per mBtu; (ii) BG Group Australia (QCLNG) 20-year US$40-80 billion Project Development Agreement reportedly priced at a 10% discount to traditional LNG from natural gas.
	Construction	10	Phase II N/A	CNOOC	
Dalian	Construction	3	Phase I2011	CNPC 75%	(i) Qatargas Operating Co. Qatar (Qatargas 4) 25-year agreement
	Approved	6	Phase II N/A		
Rudong, Jiangsu	Construction	3.5	Phase I2011	CNPC 55%, Pacific Oil&Gas 35%	(i) Shell Eastern LNG Australia (Gorgon) 20-year US$27 billion agreement at US$10 per mBtu; (ii) Woodside Energy Australia (Browse) 15-20 year US$37 billion terms agreement at US$7-US$9 per mBtu. In early 2010 the deal expired.
	Approved	3	Phase II N/A	CNPC	
Tangshan, Hebei	Approval*	6	Phase I2011	CNPC:	(i) Pars LNG Iran (South Pars phase 11) 25-year MOU agreement Indexed to average oil price
	Approval*	10	Phase II N/A	CNPC	
Qingdao	Approval*	3	Phase I2013	Sinopec	Esso Highlands Papua New Guinea (PNG LNG) 20 year preliminary agreement at US$9-US$10 per mBtu
	Approval*	5-6	Phase II2014	Sinopec	

* These plants have received initial but not final approval from Beijing.

Source: Reuters, 2010; various media reports, Priestley, 2010

Fig. 23. Additional LNG Receiving Terminals, capacity in million tonnes per year

LNG TERMINAL	STAGE	CAPACITY	STAGES	STAKEHOLDERS
Ningbo	Construction	3	Phase I2012	CNOOC: 51% Zhejiang Energy: 29%
	Approved	9	Phase II N/A	CNOOC
Zhuhai	Approved	3	Phase I2011	CNOOC: 25% Guangdong Electric:35%
	Proposed	4	Phase II N/A	CNOOC
Hainan	Proposed	2	Phase I2010	CNOOC
	Proposed	1	Phase II2015	CNOOC
Shenzhen	Proposed	-	Phase I2012	CNPC (51%), CLP (24.5%)
Qinzhou	Planned	N/A	Phase I N/A	CNPC
Zhuhai	Approved	3.5	Phase I 2013	Sinopec
		3	Phase II N/A	Sinopec
Wenzhou	Approval*	3	N/A	Xinao Gas
Rizhao	Planned	0.5	N/A	Daesung
Shantou	Construction	1.2	Phase I2012	Sinogas

* These plants have received initial but not final approval from Beijing.
Source: Reuters, 2010; various media reports, Priestley, 2010

Storage

The gas shortages experienced during the winter of 2009/2010 have increased pressure to expand the storage capacity of gas across China. China's first major gas storage site was built in 2001 providing supply security for Beijing and Tianjin. By 2009, China had around 9.3 million tonnes of storage capacity across its gas terminals. New storage facilities are planned for LNG terminals and strategic locations along the West-East pipelines. In 2010, CNPC announced plans to build 10 natural gas storage facilities between 2011 and 2015 to stockpile 22.4 bcm of gas close to their fields in Inner Mongolia, Xinjiang and Shaanxi, including a 12 bcm underground storage facility next to their Changqing field (Ordos Basin) in Shaanxi. This will increase the company's stockpile capacity from the present 3% to around 8-10%.

It is expected that the significant investment in gas infrastructure across the nation will resolve the existing tensions between supply and demand up to 2020 (IEA, 2007). However, the growing complementarities between gas-powered generation and renewable energy, such as wind and solar, combined with the rapid growth of CBM into the system will require further investment in plants, pipeline and storage capacity beyond the existing grid.

5.3. The Rise of Unconventional Gas

Unconventional gas refers to gas resources that are complex and uneconomical to exploit, such as shale gas, deep gas, tight gas, deep geo-pressurised gas, coal bed (seam) methane (CBM) and methane hydrates locked in permafrost and the deep sea. The availability of horizontal drilling and fracturing technologies combined with scales of production are opening up significant unconventional gas resources. As a result of the recent growth of shale gas or CBM, some energy commentators are referring to unconventional reserves as an industry “game changer” and even as a “conventional” gas.

China has considerable potential in their domestic resources of unconventional gas and has been working to both prove up these assets and where appropriate develop such gas reserves economically, as Stern (2008) notes:

> *To encourage CSM projects, the Government has put in place several favourable policies for the industry, including a reduced 5% VAT rate for CSM projects with foreign partners, exemption from import and other duties on materials and equipment for CSM exploration and development, exemption from royalties for CSM projects producing less than 1bcm per year; and free market pricing of gas, with no State controls …*

Despite the abundance of resources and favourable development policies, CBM development in China has proceeded more slowly than similar schemes in the US, Canada or Australia. CBM production to 2007 was a mere 200 million cubic metres; compared to a target of 10 bcm by 2010 and 20 bcm by 2015. CBM output grew to 0.5 bcm in 2008, but continued to remain well short of projections of a revised 5 bcm target for 2010, which was further revised down to 2 bcm in 2009. In contrast, coal mine methane (CMM) production reached 5.2 bcm in 2008, exceeding the 2010 target of 5 bcm. In order for China to reach its target of 50 bcm annual production of CBM by 2020, the central government estimates that a further RMB1 trillion of investment is necessary (Ng, 2009). Most of the RMB1 trillion would need to go into the construction of infrastructure to get the gas to market, but also support exploration and resource development.

While the development of CBM commenced in the 1990s in China, it has received increasing interest during the past five years. A lack of domestic technology and expertise in CBM extraction saw the establishment of China United Coalbed Methane (CUCBM) to attract international investment in the sector. Government policies including a deregulated pricing mechanisms, tax concessions and soft loans for CBM development have been only modestly successful to date. Some argue that pricing and institutional impediments within the sector are the main obstacle to its expansion, particularly the ongoing low price of domestic gas and the divide in authorisation between provincial and central governments on access to coal fields (Higashi, 2009).

CBM production is one of the key 16 projects listed in China’s 11th FYP with an initial target of 10 bcm of CBM development by 2010. However, due to the slow evolution of the industry this target was later halved to just 5 bcm by 2010. In a situation reminiscent of the NDRC’s failed goal for gas production, in late 2009 the NDRC reduced its 2010 CBM production target from 5 bcm to 2 bcm and set a 2015 target of 3.5 bcm. The 2020 target however remains in place with expectations CBM production will reach 50 bcm. By 2008, 1.6 bcm of CBM was utilised, rising slightly in 2009. This is despite the venting of an estimated 5.7 bcm of CBM annually from China’s coal mines (IEA, 2008). Investment in CBM development has remained low with estimates that a further RMB670-1000 billion is necessary by 2020 for the exploration, development and production of CBM if it is to meet the 50 bcm target (Winn, 2009).

By mid-2009, China had around 3,500 CBM wells operated by Jincheng Anthracite Coal Mining, CUCBM and PetroChina (Winn, 2009). China Electric Power noted that between 2007 and 2009, 484 MW of CBD powered generation capacity had been built with nearly 2 billion kWh of electricity generated in 2009. To date, development of the sector in China remains modest with little supporting infrastructure such as storage, pipelines and liquefaction capacity. Commercial scale CBM has already taken place, most notably in the US. However, the costs are generally higher due to the drilling requirements, the higher number of wells and the slow extraction speed.

The benefits of both CBM and CMM include safety enhancements, reduced greenhouse gas emissions and a useful transition fuel and economic resource for communities in making the shift away from a heavy dependence upon coal.[22] The potential of CMM in China is strong due to the large scale of coal mines. CMM has traditionally been released from coal mines to reduce the risks of an explosion, but new developments in drilling technology (such as horizontal drilling and rock fracturing techniques), higher gas prices prior to the GFC and higher demand for gas have witnessed a growing commercial interest in CMM and CBM.

China is the leading emitter of CMM producing around 40% of the world total or over 135 million tonnes of CO_2 equivalent in 2006 (IEA, 2009d). These figures will have increased rapidly in recent years in line with the expansion of coal mining. Tapping into CMM offers China not only the benefits of improved mine safety, but also reduced reliance upon imported gas from overseas, such as shipped LNG and piped gas. CMM development has been quite successful in the coal heartland of Shanxi[23], but is slow to pick up elsewhere in China.

In recent years, China has discovered significant deposits of natural gas hydrates or "combustible ice" on the Qinghai Tibetan Plateau and in the South China Sea. The Qinghai find is estimated to wield estimated reserves equal to 35 billion tonnes of oil. Extracting gas from the hydrates remains technically and economically unfeasible with estimates of a 15 year delay in commercialisation. Another potential source of unconventional gas is coal-to-gas. Currently, China has around 15 coal-to-gas projects under construction or in the pipeline (Xinhua, 2010c). Three plants have so far been approved by the NDRC, including the Huineng Group's 1.6 bcm project in Erdos, Inner Mongolia and two Datang Power International projects in Chifeng, Inner Mongolia and in Fuxin, Liaoning. Both of which expect to produce 4 bcm annually.

While the benefits of unconventional gas are significant, social, economic and environmental concerns relating to the extraction of unconventional gas remain, including from coal seam methane and natural gas hydrates. Such concerns arise due to the costs, method of extraction and end-use. For example, critics of CBM in the US claim the fracturing fluids, which are typically a brine, sand and chemical mixture, wield potential environmental and health impacts. According to the *Coal Mine Safety Regulation* (2006), it is forbidden to utilise coal mine methane when concentration levels are below 30% due to safety considerations.[24] The low methane concentrations also make commercial exploitation difficult resulting in the venting of the gas. Today, the government priority remains

[22] It is important to note that CMM differs from CBM because it is directly associated with coal mining activities. Trapping CMM has significant potential for greenhouse gas abatement. In contrast, CBM is a natural gas resource that requires directed mining activities for extraction.

[23] This is location of the world's largest CMM operation which uses the trapped methane to power a 120 MW electrical generator.

[24] China Coal Mine Safety Regulation (29 September 2006, effective 1 January 2007), Chapter 2. Ventilation, Article 148.

focussed on safety whilst increasing the utilisation of coal methane due to the significant environmental and economic benefits of trapping methane in coal mines.

5.4. Investment and Technology

Natural gas is one of several resources that have been allocated 'critical' status for China's future economic growth. As such, investment approval is typically 'fast-tracked' for domestic and overseas investments that secure access to gas with financing forthcoming from China's Development Bank and other state-owned lenders. In recent years, there have been several important partnerships between China's big three oil and gas companies and many experienced oil and gas players, such as BP, Shell, Total, ExxonMobil, Chevron, Korea Gas and GAIL. Domestic joint venture investments have included the extraction and distribution of gas as well as the construction of pipelines and terminal and storage facilities. International partnerships have mostly related to oil and gas extraction and securing supplies, but also included the construction of pipelines, terminals, processing facilities and LNG ships. More recently, Chinese companies have targeted overseas firms due in part to their technological expertise and experience, for instance the joint bid from Shell and PetroChina for Arrow Energy in Australia. The increasing number of international commercial partnerships and cooperation could result in benefits, including:

- speeding up the adoption of both soft and hard technologies, especially in emerging areas of energy development, such as unconventional gas and carbon capture and storage; and
- the sharing of best practice in the industry, including environmental, occupational health and safety conditions so as to reduce the risks of accidents[25] and improve efficiency.

Technology and investment will continue to be critical to the future of CBM. In 2007, China opened up to foreign investment in CBM in order to speed up the development of the sector. While new technologies have made the extraction of CBM and CMM cost effective, it remains a limited market due to the challenge of the resource. This is due to the opposite relationship between gas content and access. For example, the gas content typically increases on a linear scale with depth, yet permeability decreases on an exponential scale with depth. With new technologies, the optimum range for accessing a combination of acceptable, economical gas content and economic permeability will expand. The greenhouse gas abatement benefits of trapping CMM have availed a growing number of opportunities for funding support through the Clean Development Mechanism (CDM) of the United Nations Framework Convention on Climate Change (UNFCCC). However, the failure to incorporate CMM recovery and utilisation from the commencement of coal mine operations has reduced the opportunities for receiving CDM support (IEA, 2009d).

[25] Mine related deaths have been coming down in recent years in China, but gas explosions, flooding and collapses remain too common. In 2009, there were 2,631 official coal mine related deaths but many more go unreported. In 2003, an explosion killed 243 workers on a CNPC gas field in Chongqing and poisoned a further 4,000 others. In early 2010, twenty workers were killed in a natural gas explosion at an industrial furnace in Hebei. At the same time gas related accidents still occur overseas. For example, an explosion at a US gas power plant killed six and injured 26 workers. In 1998, an explosion at an Australian gas storage facility killed two workers. In addition to the human costs, gas accidents typically disrupt supplies.

6. Global and Regional Supply Position for Gas

Gas is the third largest global energy source after coal and oil. While the GFC led to a significant drop in global natural gas demand as well as excess capacity in 2008 and 2009[26], gas continued to account for around 20% of primary energy consumption. During the past decade, global gas consumption has increased annually by nearly 3% with China contributing to the largest growth of around 25% of total global demand. The IEA (2009a) predicts a slower expansion of global gas demand at 1.5% annually to 2030 in its reference case. This expansion in global demand will increasingly be met by imports, including LNG from countries such as Australia. Global LNG trade is projected by the IEA to rise by 3.7 per cent per year to reach 17 104 PJ (314 Mt, 15 tcf) in 2030. (GeoScience et al., 2010).

The world supply position for gas has developed significantly in the last decade (BP 2009, Stern 2008; IEA, 2009b). Compared to 30 years ago when gas was the poor cousin of oil, the situation has changed with the discovery of enormous and high quality gas resources and new technologies for commercialisation. In 2009, global reserves of proven gas reserves were estimated at around 185 tcm with around 918 tcm of global unconventional gas resources (GeoScience et al., 2010). The key official data shows the dominant share of reserves for world natural gas are located in the Middle East and Russia/Eastern Europe, with the Asia Pacific having a little less than 15%. As a result, the industry has matured somewhat with a convergence of prices and increasing global exchange of gas between regions. For example, global LNG trade expanded at an average annual rate of 6% per year over the past decade, accounting for around 7% of global gas consumption (GeoScience et al., 2010). Despite this supply side growth, there have been few material real price reductions for customers reflecting the market dominance to date of certain leading producers – especially the Qataris with their oil parity pricing approach, as well as GazProm of Russia.

There are emerging signs that current price rigidity will break down over time to the benefit of gas consumers, through:

- proactive policies aimed at diversifying European gas supplies and anti-trust action in Western Europe;
- local supply side growth in gas reserves from Qatar, West Africa, Papua New Guinea, Australia and Russia;
- the enormous expansion of LNG capacity in PNG and Australia, some of which has been deferred during the global financial crisis, and under which excess supply can be expected to influence longer term prices from 2015; and
- the discovery of new processes, and advances in technology to develop CSM deposits, that are demonstrating their potential in both China, the United States and Australia.

So it can be concluded that the prospects are positive for China not only to take infrastructure investment decisions in favour of developing its use of natural gas, but also to establish a more proactive gas policy context that facilitates a lower carbon and cleaner environment as a result.

[26] Global natural gas demand grew by 2.5% in 2008, but then declined by 2.5% in 2009.

During the past decade gas has experienced a revival with a sharp increase in the identification of diverse and abundant new gas fields on top of traditional suppliers, such as Qatar, Russia, Nigeria and Algeria. Five years ago, the EU and US were concerned about securing adequate domestic gas supplies. However, due to a combination of growing concerns about climate change and the emergence of CBM, countries across Europe and in the US are opening up previously depleted and uneconomical coal and shale deposits. New drilling technologies have opened up new supplies of gas that were initially deemed low quality or too expensive to tap into.

Since 2000, the natural gas market has grown considerably and strengthened its potential as a major natural resource in its own right. A combination of factors have merged to place gas in a competitive position alongside coal, oil, nuclear and renewables as fuel source for industry, power generation, transport and residential use. Firstly, the strong energy demands from the rapidly developing and emerging economies, such as China, India, Brazil and Indonesia, pushed the price of oil away from its historically low price to above US$100 a barrel prior to the global financial crisis and it still remains at around US$70-$80. Secondly, global recognition of carbon constraints and risks arising from anthropogenic climate change have increased the demand for low carbon alternatives and a shift away from coal as a source of energy. Thirdly, technological breakthroughs, industry consolidation and economies of scale in the gas industry have opened up significant new deposits of so-called unconventional gas. As a result, in 2007 gas overtook nuclear as the second largest source of power amongst OECD countries. In fact, gas-fired power generation made up four-fifths on incremental power amongst OECD members between 2000 and 2008 (IEA, 2009b). These developments have opened up new supply opportunities for the gas industry, which have been made even more attractive since 2009 as the price has remained below US$5 per million Btu (British thermal units), which is seen as below the benchmark of economic viability for investment in the gas industry.[27]

The future of gas supplies will continue to be linked to the fate of oil somewhat but probably more significant is the ongoing search for diverse and low carbon energy supplies in a carbon constrained environment. After an ongoing close correlation between benchmark natural gas and oil prices for the past two decades, the two diverged to their highest levels in late 2009 and again in early 2010. Typically, the price ratio between natural gas and oil varies between 1:6 and 1:12. However, the price ratio in recent months jumped to 1:21.8. While analysts argue that the two commodities will eventually realign to their historical relationship, it is clear that in the short-term this is unlikely.

Some risks arise due to a low gas price, especially for future investment in the sector. Demand will grow, but if the price is too low then investment in the development of new fields, trains, pipelines and storage will be delayed. In early 2010, the US benchmark (Henry Hub) price of gas was below US$4 per million Btu. While demand-side pressure increases when the price is low, investment in new gas fields and gas infrastructure is driven by higher prices. According to the IEA (2009b), when the price drops below US$5, companies have little incentive to invest. For example, an internationally high price for natural gas remains an important factor in Australia to the many proposed natural gas (and LNG) developments. Without a higher price, natural gas projects remain less economically

[27] According to the US EIA (2010), the Nymex April Henry Hub price was US$4.44 per million Btus (MMBtu) and the spot price averaged $4.29 MMBtu in March, $1.03 below the average spot price in February and $0.64 lower than 2009 EIA forecasts.

attractive for companies to develop. In the mid-term this could place upward pressure on natural gas prices. The key determinant will be the speed of economic growth following the global financial crisis (GFC) and the global demand for gas.

A further consideration for the delinking of gas and oil prices relates to the shift in future growth for each resource. According to the IEA (2009a), oil demand from OECD nations is likely to continue its current decline brought about by the GFC through to 2030. The IEA predict declining average annual oil demand in the US of 0.7%, 0.4% in Europe and 1.8% in Japan. In contrast, China's insatiable demand for oil is estimated to increase at an annual average rate of 3.3% through to 2030.[28] At the same time, demand for natural gas is expected to rise in Europe, North America and Japan as these countries attempt to curtail carbon emissions from coal power generation. According to the IEA (2009a) World Energy Outlook there is a close relationship between future demand for gas and climate change. In the IEA's Reference Scenario, demand for gas rises 41% between 2007 and 2030 from 3.0 tcm to 4.3 tcm respectively. This is equivalent to an annual increase of 1.5%. Even under the 450 Scenario gas demand grows but more slowly and is 17% lower in 2030 than in the Reference Scenario. The slower growth is due to slower demand, energy efficiency gains, lower electricity demand and increased switching to non-fossil energy sources.

The supply side of the natural gas sector has experienced a divide in recent years between OPEC and non-OPEC countries. While OPEC natural gas liquids production has steadily grown from an average 4.47 million barrels per day in 2007, to 4.55 million b/d in 2008 and 4.67 million b/d in 2009, average non-OPEC gas production has declined from 3.65 million b/d to 3.79 million b/d and then 3.34 million b/d respectively. Much of this is part of the long term decline in pressure from fields, but also a result of declining demand following the GFC. Natural gas prices in the Asia Pacific market also declined following the GFC.

It is expected that gas production is set to expand due to the exploitation of CBM sources in China, Europe, North America and Australia. Estimating unconventional gas supplies is difficult as most remains unmapped, but conservative IEA (2009a) estimates are 921 tcm, which is more than five times proven conventional gas reserves. In addition to the aforementioned CBM projects in China and Australia, the US, Europe, Canada and Indonesia are all exploring the future potential of CBM to contribute to the fuel mix.[29] The development of CBM will most likely place downward pressure on prices and could risk future investment in gas infrastructure. In 2008, Russia was the biggest natural gas producer. However, in recent years the US has increased shale gas production (including CBM and tight gas) to levels satisfying half of its domestic gas demand. The rapid expansion of shale gas in the US to over 600 bcm saw it surpass Russian gas production in 2009. The strong global interest in CBM has led some analysts to predict a glut of gas on international markets, which will in turn bring prices down.

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[28] The IEA (2009b) tempers these projected rises due to the increased presence of renewables and recent gains in energy efficiency, but does mention the upward pressure on gas from pairing increased wind capacity with gas-fired plants as reserve capacity.

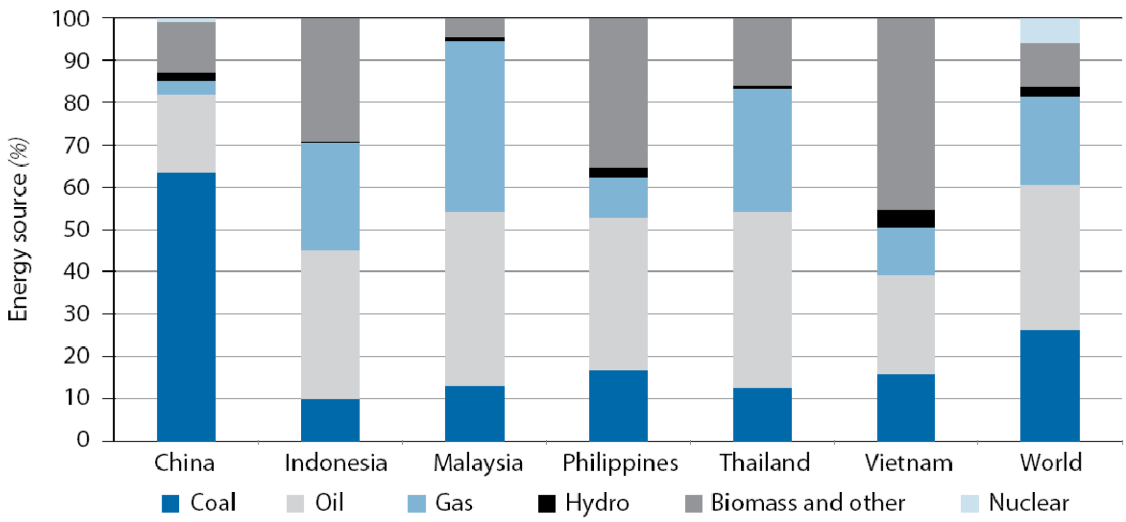
[29] In 2009, China and US signed up to a cooperation agreement on exploring the future potential supplies of CBM and sharing technology. The US shares a similar predicament with China in having large coal bed methane and shale deposits whilst searching for an alternative to a heavy domestic dependence upon coal and oil.

According to the IEA (2009a), the expansion of unconventional gas and the existing under-utilisation of inter-regional pipeline and LNG capacity wield significant consequences for the structure of gas markets, including a lower gas price and the possible de-coupling of gas and oil prices. As a result, the IEA suggests suppliers to Europe and Asia-Pacific markets are likely to modify pricing terms under long-term contracts and sell more gas on a spot basis. The outcome for gas industry investment in infrastructure and the development of new fields shall remain dependent upon the extent of growing gas demand, especially from emerging economies and the pressure to move away from coal.

Asia Pacific Developments in Gas

South East Asian countries, such as Vietnam, Malaysia and Indonesia, all have significant gas reserves and resources and are expected to further develop their respective gas policies and regulations as well as their gas production and consumption capacity. Demand for gas in the Asia Pacific is expected to steadily grow as countries strive to provide greater energy security whilst they become increasingly dependent upon energy imports. This will be especially the case for China, India, Malaysia, Vietnam, Thailand and the Philippines. As such, gas is likely to meet much of the region's growing energy demand, especially in large cities and for power generation.

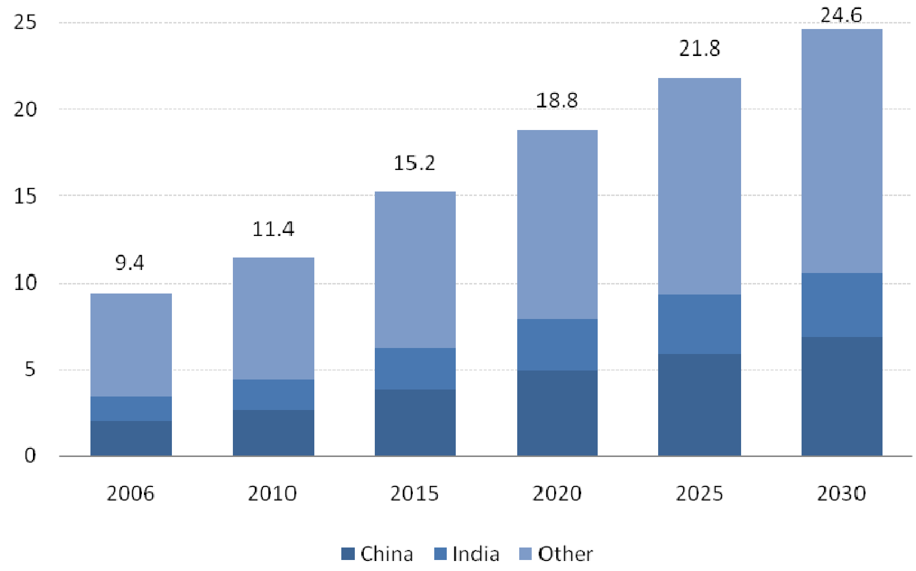
Fig. 24. Energy Mix in Selected Asian Economies, 2007, %



Source: World Bank, 2010

As shown in Figure 24, the region's larger economies heavily rely upon oil and gas, with the exception of China where coal dominates. It is expected that in the next two decades most countries are expected to gradually switch away from the increasingly expensive oil and towards gas. Combined with the growth in gas demand from China and other regional economies (Figure 25), some gas price volatility is likely.

Fig. 25. Projected natural gas consumption in non-OECD Asia, 2006-2030, trillion cubic feet



Source: EIA World Energy Projections, 2009

In 2009, Wood Mackenzie updated the expected supply and demand outlook for natural gas, LNG and CSM over the next 10 years (see Harris 2009, Quinn 2009, Wood MacKenzie 2009, and McManus 2009). The key conclusions which are of relevance to China include:

- indigenous unconventional gas production from CSM will pressure both LNG supply and pricing in the next decade (Harris 2009);
- 90 mmtpa of new LNG capacity is due to come on-stream during the next few years especially in the Asia Pacific region including exports from Sakhalin and Pluto (under construction);
- the market is expected to soften by 2010/11 reflecting a combination of significant new supply and weaker demand;
- a market tightening is expected temporarily through 2013/14, but then major softening as significant capacity extensions come on stream from Gorgon PNG LNG and QCLNG, as well as Gladstone, Icthys, APLNG, GLNG, Sulawesi, Sakhalin and Tangguh extensions; and
- Pacific Basin demand is expected to grow steadily and also become more diverse.

As Harris (2009) concludes "The wave of oil parity deals has passed … those projects expected to start post-2015 are likely to secure lower prices and may have to make other concessions to buyers".

It is expected that global oversupply will pull spot prices below oil indexed levels in the short term. Whilst Asia has commanded a premium to European prices in recent times, the arrival of new Australian supply is expected to remove this premium in the next few years. However, as mentioned, if the price falls too low then investment levels will also decrease.

Natural gas in Australia

Natural gas is one of Australia's key energy resources with abundant natural reserves of both conventional and unconventional gas. In 2009, gas reserves with reasonable prospects for commercialisation were estimated at around 60,000 petajoules (PJ), comprising more than 39 000 PJ of conventional natural gas and more than 21,000 PJ of unconventional coal seam gas (AER, 2009). Currently, most of the conventional reserves are located in off-shore fields in north-western Australia with recent discoveries in Queensland doubling the commercially viable reserves of CSG. Potential tight gas and shale gas reserves have been identified in West Australia, South Australia and the Northern Territory but are not currently being developed.

In 2008, Australia was the world's sixth largest LNG exporter, accounting for 9% of global LNG trade, but only 2% of natural gas reserves and production (GeoScience et al., 2010). However, according to the IEA (2009a), Australia is rapidly emerging as a key global natural gas player. Moreover, Australia is expected to dominate gas exports to China by 2030 with around 55 bcm of LNG shipped annually. This will equal the combined total of Russian and Central Asian piped gas into China by 2030 if the Russian pipeline is complete by 2020.[30] Australia and other Asia Pacific producers have proven LNG technology and resources and so can be seen as reliable long term suppliers contracted reliably at sub-world market prices, which are likely to remain below the current US$6-8 mmbtu in the medium to longer term. Australia's LNG export capacity is expected to increase from around 16 million tonnes at present to around 24 million tonnes by 2011-2012 and 76 million tonnes by 2029-2030.

According to Robinson, the CEO of the Australian Petroleum Production and Exploration Association, in 2009 natural gas is "the key to assisting Australia and the world make a smooth transition to the substantially lower or no emissions future that must lie ahead." Her comments epitomise the commitment of the petroleum industry to the development of natural gas based power generation and the use of gas more generally. Much of this optimism is a result of multi-billion dollar LNG agreements between China and Australia.[31]

The institutional arrangements in Australia for gas and electricity are quite different to international experience. Moreover, recent investment evidence demonstrates that the Australian energy market environment is facilitating the entry of gas and renewable based power generation capacity as a commercial priority. The Federal and State or Regional governments of Australia have combined to oversee a National Energy Market (NEM) for Electricity and Gas. In the former case electricity generators are required to bid their energy from different sources and operating costs into a wholesale market, which sets posted prices by volume of power (GWh) and time of day against which electricity customers can buy their energy. The same process applies for gas, and the prices of the two markets have the potential to be interconnected, post their move to supervision under the National Regulator and Market Operator – AER, and NEMMCO respectively - as from 1 July 2009.

That means at the wholesale level, there is a different price applying at different peak and off peak times during the day, and the price path is higher at peak – that encourages higher cost peaking

[30] If delays continue to impede negotiations for the construction of the Russia-China pipeline (Chen, 2010), then China would most likely consider increasing the capacity of existing Central Asian (mainly Turkmenistan) contracts beyond the existing 40 bcm annually.

[31] Following the signing off of the Gorgon LNG and Gladstone CBM projects, the Australian Minister for Resources and Energy, Martin Ferguson argued that "Australia is a safe place for investment, there is no sovereign risk and we are a major energy player internationally when it comes to clean energy, namely LNG" (Kirk, 2010).

capacity to be economic. Due to these features in the NEM, gas fired power generation is acknowledged and plays a key role for its superior operating features:

- immediacy of connection to the grid, compared to other base load generators that take time to both fire up and be brought on line, as well as the reverse;
- 50-70% less carbon dioxide than conventional coal fired generation;
- gas fired generation uses very little water – as little as half to 1/2000th of the water used by coal fired power stations;
- a smaller environmental footprint – 15 hectares per 100 MW plant compared to 7000 hectares on average for solar and 10,000 hectares for wind; and
- gas is the perfect complement for intermittent renewable energy sources feeding into a power grid - South Australia's Electricity Supply Planning Council notes that every 5000 MW of wind power requires around 2000 MW of gas fired generation to ensure a reliable supply to the energy grid.

The Australian NEM has led to more diversified electricity sourcing and use. For example, more than 6000 MW of open cycle and combined cycle gas turbines and traditional gas power generators are proposed for addition to the national energy grid during the next four years, and the regulator is already working on a pro forma code for the market to adopt carbon pricing, subject to the final shape of policy decisions from the Australian federal government and parliament.

There is considerable scope for ongoing and enhanced cooperation between China and Australia on gas. In addition to the commencement of a strong gas supply relationship and Chinese investment in Australia's gas resources, the value Australia has to add in this field is primarily through the opportunity to apply learnings in this country from recent developments in Australia's energy resources and markets, as well as the adoption of smarter environmental approaches to ensure these energy markets provide cleaner and greener energy solutions. At the same time, LNG from Australia is currently offering the lowest price and will therefore play an increasingly important role in Chinese gas imports.

The CSM market has grown significantly since its formative stages of the 1990s. As from 2006, significant reserves in Australia have been upgraded across the board, and major oil and gas producers like BG, Santos, Petronas, Origin, Conoco Phillips, Arrow Energy and Shell have moved to secure CSM resources, as the race is on to develop the first CSM to LNG project. The technology to do this is known, and fit for purpose rigs are available for the task. Modern water management innovation technologies and systems also make this form of resource more accessible today. Whilst the immediate challenge is to develop such resources commercially, the mood of optimism is high. It reached its peak following the March 2010 signing of a major gas deal by CNOOC for the supply of 72 million tonnes of coal seam methane over 20 years. The Australian Minister for Resources and Energy, Martin Ferguson, then announced that from an "energy and a resource point of view, Australia's very important to China's future economic development" (Kirk, 2010).

The recent growth in gas exploration in Australia is led by offshore exploration in the north west shelf and the development of new coal seam methane fields in Queensland. These two major developments have lifted investment in gas exploration to its highest levels on record in recent years.

Australia is set to become the largest exporter of unconventional gas with the announcement over the past few years of several multibillion-dollar offshore gas projects in the north west shelf and coal seam methane to liquid natural gas projects in Queensland (Smith and Hoyos, 2010).[32] Rather than develop the gas for domestic markets, most of the gas is to be used for long-haul exports to China, Korea, Japan, Singapore and Taiwan.

CNOOC signed a deal in 2009 with BG for the delivery of 5.3 bcm annually over 20 years from the planned Queensland CBM development. The recent 20-year gas supply contract between Exxon Mobil and CNPC from the Gorgon fields was greeted with much debate in China due to the one third higher price paid by China compared to a similar deal reached with India. China analysts suggested Exxon's shareholdings in the India partner, Petronet8, ensured that a preferential price was achieved.

7. Policy Options for the Increased Utilisation of Natural Gas in China

This note presents seven major policy suggestions that may contribute to the existing Chinese Government's actions to reduce carbon emissions through the increased utilization of natural gas. The Chinese Government acknowledges the substantial benefits natural gas offers to China as: (i) an ideal low-carbon transition fuel for the shift away from coal and oil and towards renewable energy offering a 50% to 70% reduction in CO_2 emissions per unit of energy in many uses compared to coal and oil; (ii) a potentially low cost fuel for pairing with intermittent power generation, such as renewable energy sources; and, (iii) an effective, modern and cleaner fuel source for residential, commercial and industrial uses with significantly lower levels of SO_2, NO_x and particulates.

The policy options presented in this note draw upon CSES and other analysis of actual and proposed policy responses in China and other jurisdictions and include the following suggestions:

1. Adopt a national low-carbon energy policy
2. Prioritise pairing of natural gas with intermittent renewable energy
3. Incremental phase-in of regional and national gas market
4. Directed state investment in strategic international investments and partnerships in the gas sector and natural gas infrastructure
5. Trial new financing techniques for energy infrastructure
6. Provide clear direction for future natural gas utilisation
7. Encourage distributed generation of low carbon gas sector

As mentioned earlier in this report, China acknowledges the benefits of natural gas and is moving actively towards realising many of these policy suggestions by developing a comprehensive energy framework supportive of natural gas. It is important that these policy suggestions are assessed against this framework.

[32] Smith (2009) noted that CBM could account for up to one-third of Australia's gas projects by 2020.

Implement a national low-carbon energy policy

i. Proposed policy

Fully implement existing national energy policies with a priority on promoting the increased utilisation of low carbon energy sources, especially renewables.

ii. Rationale

The existing national energy policy should further consolidate the existing regulatory and pricing framework of energy policies, plans and legislation (including the draft Energy Law) to facilitate the transition towards a low carbon economy. Such a policy could incorporate a carbon tax, an emissions trading scheme, renewable energy targets and be linked into a global climate change agreement to facilitate international financial and technical assistance. Identifying natural gas as a "clean and reliable" priority fuel for the transition to a low-carbon economy should be considered.

iii. Policy details and implementation

A. The establishment of a national carbon tax and emissions trading scheme ensures that pricing of resource use includes economic, social and environmental externalities. A carbon tax should incorporate social/environmental externalities and measuring energy intensity; GHG (CO_2) emissions; particulates; water use etc. Such a measure will curb the expansion of black coal fired power plants and facilitate the further development of power generation from renewable sources and substitute power sourcing more towards gas based plants. [33]
B. Government to assist energy industry in identifying strategic pilot cities for development of integrated low carbon and renewable energy supplies together with cogeneration and even tri-generation capacity.
C. Develop pricing and regulatory support for development of distributed power generation of low carbon energy resources, such as the use of ceramic fuel cells powered by natural gas. Unit subsidies, feed-in tariffs and VAT rebates should be directed towards providing sufficient incentives for investment in reliable and low carbon power generation.[34]
D. Government funded infrastructure for pipelines, energy storage facilities.

Prioritise pairing of natural gas with intermittent renewable energy

i. Proposed policy

Prioritise natural gas as a complementary load power source for intermittent renewable energy

ii. Rationale

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[33] Evidence published by Australia's leading upstream and downstream energy producer and retailer, Origin Energy, shows that the current indicative global benchmark price for carbon emissions of $US20/tonne equalizes the short run marginal costs of base load power generation from coal and gas sources, and carbon prices above this will both favour and facilitate a substitution towards gas based power generation, and away from black coal.

[34] In May 2010, the State Council (2010) announced that CBM would be eligible for feed-in tariff support.

Pairing dispatchable natural gas generation with renewable energy, such as wind and solar, offers a natural symmetry due to the intermittent nature of renewables and natural gas' reliable, fast start and stop and flexible operation features.

Pairing improves energy mix security through diversification and provides a stronger incentive for grid connectivity and utilisation rates for renewables, as well as reduces CO_2 emissions and other pollutants, such as NOx, SOx and particulates in comparison with coal power plants. Pairing offers additional benefits, such as improving economic viability of new transmission lines to connect wind and solar resources into the electrical grid. In addition, the reliability of pairing power sources provides added leveraging in contract price negotiations, which can keep costs low, particularly if gas is supplied through trunk feed line with generous maximum daily quantities (MDQs) to ensure greater flexibility.

iii. Policy details and implementation

A. Government can provide additional tax incentives, soft loans, VAT rebates, feed-in tariffs, technical assistance and target regions for development. The Government could consider introducing preferential loan and tax policies for the development and use of natural gas with renewables in power generation. Support should be available during construction stage as well as power generation with tax exemptions and VAT refunds. The existing 50% reduced rate for loans to the renewable sector could be extended to include projects involving paired renewable-natural gas power generation.

B. Prioritise pairing in areas with local gas supplies or access to tap into gas pipelines and significant renewable capacity, such as Xinjiang, Gansu, Inner Mongolia and Qinghai.

C. Pairing natural gas with renewables should be incorporated within broader reforms to pricing and policy measures. The draft Energy Law should replace the existing 'Policy for Natural Gas Use' (2007) which only provides a temporary bridge for the natural gas sector in China. The new Energy Law should include sufficient detail to promote the pairing of natural gas with renewable as a priority area for natural gas utilisation. If the promulgation of the Energy Law is delayed then the 2007 Policy should be reviewed to: firstly, support the transition from an allocated and 'price plus cost' system to a market orientated one; and secondly, to expand the categories of priority natural gas use to include measures to promote the pairing of natural gas with renewables.

This study suggests that natural gas can play an increasing role in China's power generation mix by replacing old, less efficient and more polluting coal power plants as well as being cited with large scale renewable sites to maximise the capacity of renewable energy generation with back-up secure and reliable base load power. Unless policy and pricing reforms are undertaken to provide incentives for shifting towards a complementary relationship between gas and renewables, then it is unlikely to occur. Firstly, investment for building a new gas plant needs security in terms of utilisation rates of capacity, which has been seriously weakened during the past two years. Secondly, the experience to date has shown that rather than complement each other, gas is actually competing with renewables due to their similar higher pricing levels; making them only attractive during demand peaking periods.

Incremental phase-in of regional and national gas market

i. Proposed policy

Accelerate the current shift towards establishing a regional and national natural gas market on a progressively staged basis to eventually replace existing allocation and "cost-plus" system of pricing.

ii. Rationale

The advantages of future national or regional electricity and gas markets for China would be:

- feeding in gas fired generation to an optimised electricity grid with a full range of wholesale sources of primary energy; and
- building a deeper and more flexible market for gas itself by having a focus for more rational wholesale and retail price determination, that would restructure current customer price rigidities impeding the development of gas.

Furthermore national and regional energy markets in China would facilitate the NDRC taking a position to oversee the introduction of carbon pricing across the placement of various bids into the respective energy markets at the wholesale and retail level. These carbon cost (tax) impositions and subsidy credits would enable a more transparent pricing of the environmental impacts of various primary energy forms and also cement the relatively advantaged environmental position of gas, both for power generation and for other uses. Use of a wholesale market in this way would simplify and allow an efficient carbon tax collection, as on line market data and bidding / supply sources would facilitate live tax data and collection 'on line'. See Appendix 1 for a more detailed description of Australia's energy market, including details of the gas market Bulletin Board and the Short-term Trading Market.

Pricing systems should be increasingly transparent to improve efficiency in supply and demand relationship and promote energy investment stability. The current 'Policy for Natural Gas Use' (2007) remains a stop-gap measure which insufficiently resolves existing structural and pricing problems within the natural gas supply, distribution and demand systems. The existing "cost-plus" based domestic pricing system has kept domestic gas prices below international levels. The greater reliance on higher priced gas imports will weaken the viability of the existing system. However, it will be necessary to maintain the existing policy to foster higher investment in infrastructure and use during the transition period to greater marketisation.

iii. Policy details and implementation

A. Review the restraints with the existing 'Policy for Natural Gas Use' by progressively establish pilot regional markets for electricity trading at the wholesale level along the eastern seaboard as gas and electricity infrastructure capabilities integrate and as wholesale energy markets and applications progressively mature.

B. Sector based policies could include the following:
   a. *Domestic* – retail consumers should be paying the full economic costs of using natural gas in all major urban centres by 2015. Where possible, exclusive mandates should be provided for gas based reticulation only in new urban developments for power, heating and cooking using distributed generation, such as ceramic fuel cells or solar-gas cogeneration units for example.
   b. *Light Industrial and Commercial* – energy taxes and subsidies should be developed and used to ensure gas based power is the most economic for the majority of these customers by 2020. It will be feasible for many users to adopt distributed generation, such as ceramic fuel cells.
   c. *Heavy industrial users* – e.g. power generation, metal smelting, large chemical, cement and other manufacturing plants. The State should support, at least for a transitional period, the infrastructure costs and delivered prices to encourage large scale users to switch to natural gas, without significant penalty, so that natural gas becomes the preferred primary energy form
   d. *Fertiliser Subsidies* – the current scheme of perverse subsidies for the use of gas in fertilizer and related rural industries should be phased out within 5-7 years.

C. Initially, large electricity suppliers and customers in a nominated major region should be compelled to put their supplies through by a bid and offer process within a wholesale operator / market regulator, on a time of day basis. All new contracts could be required to be put through the wholesale regulator. The Australian Energy Market provides a possible model for this first stage of wholesale electricity trading in China.

D. Accelerate work on connecting national electricity grid to support energy diversity.

E. Introduce pricing system that progressively incorporate the full transparency of economic costs for the various primary energy forms in use to deliver electricity to domestic consumers, light industrial and commercial, heavy industrial users and fertiliser industry.

F. Domestic retail gas supply and demand sources by region can be factored in after the market has been developed. Market orientated reforms need to incorporate strategic consideration of seasonal, regional and inter-sectoral variations between supply and demand which are presently causing structural problems.

G. Continuing to reduce the gap in prices between international and domestic prices ensures gas prices better reflect actual costs to ensure the most efficient utilisation of natural gas.

H. Carbon taxes and green energy tariffs can be introduced to improve the functioning of the market from a sustainability perspective.

I. The energy market exchanges can then be interlinked to become multi-regional, and then finally to be national in nature.

J. Undertake a national natural gas resources assessment and review to assess demand/supply and cost/benefit energy relationship for natural gas covering, for example: i) supply through pipeline, terminal, or local domestic source (including CSM); ii) industry value chain; iii) low carbon cities (use by industry, heating, cooling, power generation and industry); iv) power generation; and v) state investment in IGCC/CCGT/CSM/CCS.

K. Commit resources to rigorously assess, refine and progressively develop an economic profile for the proving of reserves, confirmation of calorific values, extraction costs per GJ, wellhead values, treatment and transmission costs, and estimated city gate prices from its most economic CSM fields.

iv. Advantages and limitations

It is envisaged that such a system would provide significant economic benefits including securing ongoing levels of investment in energy supply (generation and transmission), competitive electricity prices and improved productivity with improved efficient allocation of energy resources and capital utilisation. Should result in the removal of perverse subsidies for fossil fuel use (consider phasing out where social welfare implications are identified).

Intensify directed state investment in strategic international investments and partnerships in the gas sector and natural gas infrastructure

i. Proposed policy

Further boost state investment in natural gas infrastructure and supply at the domestic and international level. Develop stronger alliances and partnerships with leaders in the global natural gas industry, especially with companies involved in emerging areas of natural gas technology and development across the gas spectrum of exploration, extraction, processing, transmission and distribution, storage and utilisation.

ii. Rationale

By investing in natural gas supply and infrastructure the state will cover the significant initial set up costs for natural gas which can act as a hindrance for investment and market access, as well as ensure access to reliable supplies and state of the art technology and world’s best practices in an emerging resource recovery sector. State support for research and development as well as targeted investment in new technology and emerging areas of natural gas supply and utilisation, such as coal seam methane, Combined Cycle Gas Turbines (CCGT), Integrated Gasification Combined Cycle (IGCC) and distributed generation, should be promoted to ensure China is utilising state of the art processes.

China currently adopts an “engaged investment” policy approach in negotiations regarding long-term commitments to gas purchases often involving underwriting the construction of transportation infrastructure up to the delivery point. The currently depressed natural gas market provides an ideal period for China to proactively engage in strategic mergers/partnerships (including ‘production sharing agreements’) for diversifying NG supplies. It is likely that oil prices will return to the peak prices of 2008 within the next 3-4 years as demand from China grows as the global economy recovers. Ongoing Government support for the partnerships approach adopted by China’s gas players of China National Petroleum Corporation (CNPC), Sinopec and China National Offshore Oil Corp (CNOOC) is essentially, especially in developing economies and will position China ahead of competing bids from Europe and North America in particular. Continued diversification of NG supplies with multiple import options is critical for sector stability in terms of supply and pricing. Moreover, such diversification increases leveraging with potential and actual suppliers of gas.

iii. Policy details and implementation

A. Commit to further investment in and ownership of long-term contracts for natural gas supply beyond existing minimum requirements.

B. Continue to accelerate the development of an integrated gas based infrastructure, combining both natural gas and LNG treatment facilities. This could include prioritising the integration of gas supplies with gas based power plants operating in the largest and fastest growing urban centres.

C. Develop demonstration power plant / grid projects from natural gas and renewables. Such demonstration projects should possibly be located within smaller rural communities with currently limited but emerging power needs, and where adjacent to potential or actual off-take points from nationally commissioned gas transmission, distribution and other infrastructure facilities. The recent announcement of a totally solar city of the future should be taken further with the development of a regionally based power generation system, where gas and renewable (e.g. wind and solar) primary energy sources form the greatest share.

D. The NDRC’s four point natural gas plan requires companies signing long-term import contracts for overseas LNG to hold equity in the upstream resource. For instance the 2010 announcement by CNOOC to purchase 3.6 million tonnes of LNG over 20 years from Queensland’s CBM fields involved a 10% stake in infrastructure and a 5% stake in the field. This vertically integrated requirement has been somewhat onerous due to the strategic nature of such investments in some countries and the potential delays in developing overseas partnerships, but with further government support should.

E. Complement policy with the introduction of renewable and low carbon energy targets and carbon pricing.

F. Targeted energy efficiency measures for industry could promote adoption or switch to natural gas utilisation. For example, a tightening of the scheduling system and the introduction of differential prices for industrial and residential users, as well as preferential on-grid price for generation using natural gas and coal-bed methane as feedstock whilst encouraging power generation with industrial waste heat (combined heat and power).

iv. Advantages and limitations

Provide increased energy security in terms of access to NG supplies at reliable prices.

The provision of gas infrastructure, such as underground gas storages, port facilities and terminals, pipelines and liquefaction will ensure optimal capture of the most economic set of natural gas sources and delivered costs of supply – especially from the second West East Pipeline, and also the Central Asia and Eastern Siberian pipelines.

The very large number of potential investments and development projects in LNG will offer significantly improved long term contractual pricing opportunities to match or significantly improve upon the $3.05/BTu gas that China has purchased from Woodside in the north west shelf of Australia, and which currently is transformed via the Shenzhen terminal into gas used to generate and supply electricity to Hong Kong.[35]

The development of demonstration projects provide experience in managing a power grid where the complementary diversity of gas and renewables can be trialled, and learning experiences documented and used to underpin similar and larger developments elsewhere.

An expansion of the domestic use of gas will give both demand diversity and load factor that will help amortise China's large capital investments in gas pipelines and treatment facilities, and encourage larger scale applications for gas, as other initiatives, such as those suggested above, have time to take effect through the progressive removal of the current price disparity for gas, vis-à-vis other fossil fuels.

Current evidence is that the consumer sector in major cities like Beijing and Shanghai are prepared to pay close to world benchmark domestic prices for using natural gas with heating, cooking and other consumer applications.

[35] In 2008, prices for imported NG varied from $3.05 MBtu to $20.60 per MBtu.

Trial new financing techniques for energy infrastructure

i. Proposed policy

Prioritise the trialling of Public Private Partnerships (PPP) and 'Alliance' structure arrangements in the energy sector.

ii. Rationale

New financing techniques can strategically attract investment that includes both soft and hard technologies and processes.

iii. Policy details and implementation

Public Private Partnerships (PPP), and 'Alliance' structure are two forms of financing that may be of value to the priority being set for developing China's gas based infrastructure. These structures began in the United Kingdom in the 1990s, and have been extensively used in Australia over the last decade. They are essentially joint financings between the public and private sectors.

Alliance structures are more like an unincorporated joint venture, and are used more widely in infrastructure developments – where a high degree of innovation is required; where the asset is complex to construct, and the ultimate owner, e.g. a Chinese Government entity both wishes to own the ultimate commissioned asset but also to learn from the best in the international industry that specialises in the relevant plant or process development. Whilst China is well advanced in LNG terminal development and has some gas powered generation, the latest technology in these areas together with recent innovations in CCGT, OCGT, and CSM development may make PPPs/Alliances worthy of further review and potential application to China's energy future.

Prioritise the construction of SCGT/CC (semi-closed gas turbine/combined cycle) dual-fuel gas and coal power generators, Combined Cycle Gas Turbines (CCGT) and Integrated Gasification Combined Cycle (IGCC), with and without carbon capture and storage (CCS) capabilities, for new power generating capacity.

The expansion of CCGT and IGCC will improve resource efficiency, reduce CO_2 emissions and curb the expansion of black coal fired power plants and substitute sourcing more towards gas based plants. More aggressive policies are necessary if China is to shift away from its current unsustainable trajectory of continuing to rely upon coal.

iv. Advantages and disadvantages

PPs and Alliance structures are designed to leverage both the quantum of finance and mutual skills and experiences in project design, development, construction, commissioning and operation. Other characteristics which improve the suitability of a PPP are:

- complex and long term infrastructure;
- clearly defined outputs;

- scope for innovation;
- balancing of risk between public and private participants;
- opportunity to bundle contracts; and
- complementary commercial development, for example, as may be applicable in CCGT developments.

There are tax features that can advantage the private participants that reflect the distinction between an operating lease and financial lease, with PPPs being more like the former.

Provide clear direction for natural gas utilisation in future energy mix

i. Proposed policy

Set transition targets for the utilisation of natural gas across regions and power utilities between 2020 and 2050. For example, the Government could propose a primary energy source peaking target composed of "three one-thirds" by 2050: 1/3 coal; 1/3 NG/nuclear; 1/3 renewables/ hydro.

ii. Rationale

Clarifying the role of natural gas as a transition fuel towards the shift to a low carbon economy should provide added security of investment, supply and utilisation rates within the sector. Current estimated primary energy share of 3-5% from natural gas and 70% from coal by the end of the decade is not sustainable, particularly when world current primary energy shares from natural gas average 20%, and are targeted to increase from this, having regard to recent discoveries of extensive and economically recoverable coal seam methane (CSM) deposits, and gas reserves capable of economic conversion to LPG.[36] By way of example, Hong Kong currently averages 'one third' targets for each of coal, gas, and nuclear.

iii. Policy details and implementation

Set progressive targets for provincial/municipal levels and energy utilities especially for the pairing of natural gas with renewables, including incentives and bonuses for exceeding targets or penalties for non-compliance. For instance, interim low carbon energy targets of 20% paired renewables-natural gas in the energy mix by 2020. This policy should be incorporated within the new national energy law.

The economics of such decisions will be enhanced as and when carbon pricing becomes either a national and /or global standard. Opportunities for availing such projects of CDM funding should be seriously considered due to the abatement benefits of increasing the currently low utilisation rates of low carbon energy sources.

[36] Domestic natural gas resources are based on a 2005 national survey which identified 56 tcm of domestic gas with 22 tcm of recoverable resources. CNPC announced in 2008 that proven reserves are estimated at 5.94 tcm. Coalbed methane resources are estimated at 37 tcm within geological resources and 134.3 bcm of proven resources. Source: IEA (2009) *Natural gas in China: market evolution and strategy.*

iv. Advantages and limitations

Ensure meeting desired economic and environmental goals. Result in substantially reduced, cleaner and more sustainable carbon footprint.

Resistance from coal sector and regions due to loss of income and employment can be reduced through increased utilisation of CSM resources.

The significant majority of new and economic additions to Australia's electricity grid are from committed investments in CCGT and related plants.

CDM could be utilised to facilitate low carbon technology transfer through investment/ financing/R&D protocols, which could encourage CSM, CCCG, IGCC or CCS activities.

This policy could reduce the resistance from the coal sector and coal regions of a low carbon policy (due to loss of income and employment), through strengthened investment in the development and technologies in reducing the GHG emissions from coal.

Encourage distributed generation of low carbon gas sector

i. Proposed policy

Review existing 'Policy for Natural Gas Use' to support distributed generation capacity.

ii. Rationale

It is expected that the natural gas power sector will diversify in the coming decade and undergo a gradual shift away from centralised power generation and move towards distributed generation due to the development of more efficient localised generation capacity, such as gas-powered fuel cells and solar-gas units which can provide cogeneration and eventually trigeneration cooling, heating and power (CHP). Distributed generation offers lower costs an[37]d a more efficient utilisation of remote and localised gas fields without the significant investment in infrastructure, such as pipelines, technology and liquefaction. Distributed generation and the use of fuel cell technology will suit new residential developments and existing commercial sites particular the replacement of industrial heating and power generation boilers.

The successful example of Broad Air Conditioning, which utilises natural gas for central chillers and waste heat provide a useful platform for linking up with solar systems or new high temperature ceramic fuel cell technologies which also utilise natural gas and have the potential for trigeneration

CHP. These units only produce around 20% of the carbon emissions of coal-powered electric equivalents.

iii. Policy details and implementation

- Review existing ‘Policy for Natural Gas Use’ to support distributed generation capacity.
- Provide purchase subsidies, feed-in tariffs and discounted VAT for the purchase of distributed units, such as ceramic fuel cells with CHP capacity of 2kW or greater.
- Local conventional and unconventional supplies of gas need to be included in this policy. For example, the government’s closure of small scale coal mines in recent years could be accelerated by focusing upon the utilisation of Abandoned Mine Methane (AMM) in feasible circumstances.

8. Conclusion

China's natural gas market is entering an exciting period against a background of LNG capacity developments, significant infrastructure expansions, long term low global prices, strong prospects of further unconventional gas resources in the form of CSM and additional diversity on the supply side. China has matched its growing need for energy with a proactive overseas search for diverse energy supplies, including joint ventures, direct investments, acquisitions and resource-loan deals for access to new oil and gas fields. China's increasing interest in overseas oil and gas ventures has coincided with a lull in international investment in the area following the global financial crisis and tightening financial conditions. Even under a high global gas price scenario, it is likely that a combination of higher oil costs and the ongoing rapid expansion of energy demand will result in gas demand exceeding the capacity of gas supplies. Therefore, gas is more likely to flow into higher value added streams, such as power generation, residential heating and cooking use in wealthier coastal cities and as a mass-transit transport fuel.

The impact of international gas prices on China's ability to secure long-term low-cost supplies of gas is an important consideration. The difficulties experienced globally due to the rising cost of developing natural gas and LNG projects, including transport infrastructure, combined with the tightening of global credit markets and lower gas prices have pushed up the cost and delayed many gas projects. In the short-term, this could benefit China's domestic gas market as well as overseas investments. If China is unable to meet expected future gas demand through LNG imports, then it will accelerate the development of domestic CBM resources and piped gas from Central Asia. Moreover, China is able to mitigate to some extent the international cost and financing difficulties, due to its lower construction costs and strong local lines of credit.

This study suggests that natural gas can play an increasing role in China's power generation mix by replacing old, less efficient and more polluting coal power plants as well as being cited with large scale renewable sites to maximise the capacity of renewable energy generation with back-up secure and reliable base load power

Further Work

On the basis of this research report, the following issues are suggested for further consideration:

- Identify the necessary costs, barriers and opportunities for installing and utilising complementary load power source for intermittent renewable energy and the potential of distributed natural gas based power generation facilities;
- Consider adjustments to existing and future pricing and wholesale and retail markets for both electricity and gas trading which facilitate cleaner primary energy usage, and an improved system for determining wholesale and retail prices;
- Examine global supply perspectives and Australian developments of gas, LNG, and coal seam methane (CSM) relative to their potential applicability for the adoption of new technologies in these areas and of relevance to China;

- Review and assess global and Asia Pacific opportunities for supply – demand balances with gas, as well as short, medium and longer term scenarios for LNG pricing, having regard to CSM;
- Examine the role of wholesale electricity markets in applying carbon pricing, and the adoption of a broader mix of power generation sources from black coal, gas, and renewables (solar, wind geothermal and biomass);
- Review relative prices and uses for gas products between the broad groups of fertilizer production, industrial applications, and consumer market uses; and,
- Review the potential applicability of alternative infrastructure financing mechanisms, such as those currently in use in Australia that could be of relevance to China, including 'Alliance' funding structures and other 'Public-Private-Partnership' (PPP) vehicles.

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Appendix A

Briefing Paper on the Australian Energy Market prepared by the Department of Resources, Energy and Tourism

Australian Energy Market

Australia's institutional arrangements are underpinned by a number of energy market reforms, the direction of which have been determined by two intergovernmental bodies, the Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE). COAG is the peak intergovernmental forum in Australia, and comprises the Prime Minister, state premiers, territory chief ministers and the president of the Australian Local Government Association. The MCE comprises Australian, state and territory energy ministers. Ministers from New Zealand and Papua New Guinea have observer status.

The process of energy market reform has been steadily unfolding over the last two decades. Since 2004, the COAG-agreed Australian Energy Market Agreement (AEMA) has formed the basis for a transition to national energy regulation; the most recent wave of reform is underpinned by revisions to that agreement in 2006.

Regulator and Market Operators

The national energy framework in Australia is underpinned by three key agencies, the Australian Energy Regulator (AER), the Australian Energy Market Commission (AEMC), and the Australian Energy Market Operator (AEMO).

The AEMC has responsibility for the rule-making process and market development in the national energy market, as legislated by the National Electricity Law and National Gas Law. The AEMC also undertakes reviews of the energy market framework and provides policy advice to the MCE.

The AER is the national energy regulator. In the National Electricity Market (which includes all jurisdictions except Western Australia and the Northern Territory) the AER is responsible for both the regulation of electricity transmission networks and electricity distribution networks. For Australian gas networks, the AER regulates covered gas transmission and distribution pipelines in all states and territories of Australia (except Western Australia). The Economic Regulatory Authority is responsible for regulation in Western Australia.

The AEMO is a single, industry-funded national energy market operator for both electricity and gas, which commenced operation on 1 July 2009. AEMO merged the role of the current National Electricity Market Management Company (NEMMCO) with the gas market functions of the Victorian

Energy Networks Corporation (VENCorp), the Gas Market Company (GMC) (which previously operated in New South Wales and the Australian Capital Territory), and the Retail Energy Market Company (REMCo) (which previously operated in South Australia and Western Australia).

National Electricity Market

The National Electricity Market in Australia is operated by AEMO (previously NEMMCO) in the following Australian states and territories: South Australia, Tasmania, Victoria, the Australian Capital Territory, New South Wales and Queensland. It operates as a wholesale pool market through which generators and retailers trade electricity. AEMO coordinates a central dispatch to manage the wholesale spot market. The process matches generator supply offers to demand in real time. AEMO issues instructions to each generator to produce the required quantity of electricity that will meet demand at all times at the lowest available cost, while maintaining the technical security of the power system.

National Gas Market

Natural gas in Australia is mostly sold under confidential, long-term contracts. There has been a trend in recent years towards short-term supply, but most contracts still run for at least five years. Wholesale gas contracts typically include *take or pay* clauses that require the purchaser to pay for a minimum quantity of gas each year regardless of the actual quantity used. Prices may be reviewed periodically during the life of the contract. Between reviews, prices are typically indexed, and therefore do not tend to fluctuate on a daily or seasonal basis.

There is some secondary trading in gas, in which contracted bulk supplies are traded to alter delivery points and other supply arrangements. *Backhaul* can be used for the notional transport of gas in the opposite direction to the physical flow in a pipeline. These arrangements are most commonly used by gas-fired electricity generators and industrial users that can cope with intermittent supplies. A *gas swap* is an exchange of gas at one location for an equivalent amount of gas delivered to another location. Shippers may use swaps to deal with regional mismatches in supply and demand.

A gas market Bulletin Board further provides transparent, real-time and independent information to gas customers, small market participants, potential new entrants and market observers (including governments) on the state of the gas market, system constraints and market opportunities. The Bulletin Board commenced on 1 July 2008 and is a website (www.gasbb.com.au) covering major gas production fields, storage facilities, demand centres and transmission pipelines, in southern and eastern Australia. Information provision by relevant market participants is mandatory and covers:

- gas pipeline capacity and daily aggregated nomination data;
- production capabilities (maximum daily quantities) and three-day outlooks for production facilities; and
- storage capabilities and three-day outlooks for storage facilities.

In addition, the MCE has approved the development of a short-term trading market in gas, to commence by winter 2010. The proposed market is intended to facilitate daily trading by establishing a mandatory price-based balancing mechanisms at defined hubs. The market would initially cover network hubs in New South Wales and South Australia and replace existing gas balancing arrangements. Victoria has had a transparent balancing market since 1999.

Source: AER (2008) *State of the Energy Market 2008*, Melbourne, Australian Energy Regulator (AER).