WILL THERE BE A TWO-TIER* LNG CONTRACT PRICING MECHANISM IN ASIA?

**Traditional oil-linkage and gas-on-gas hub linkage*

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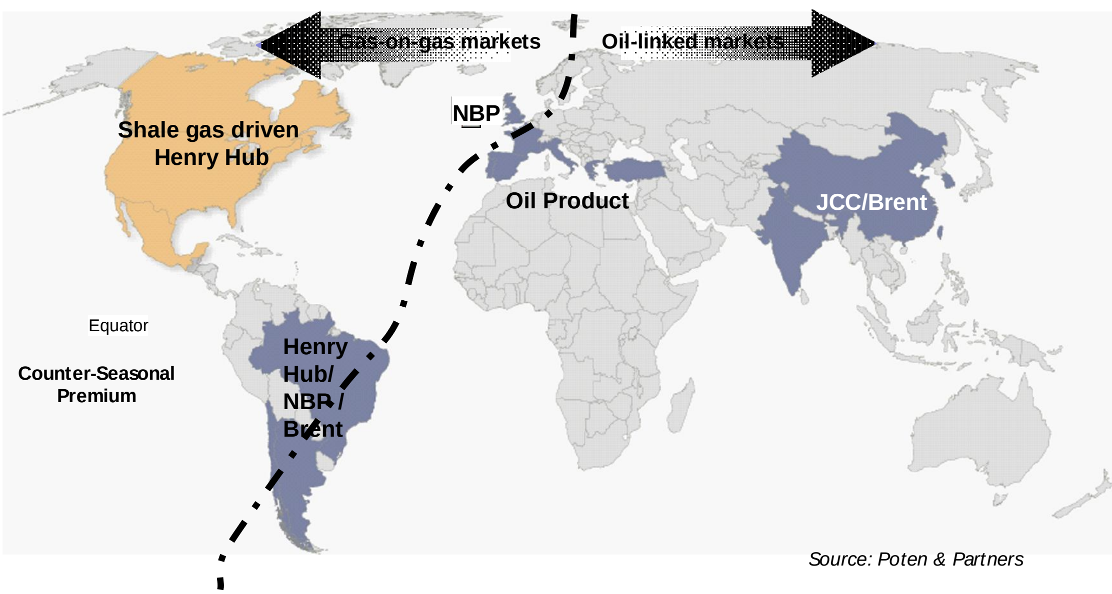
Keywords: 1. LNG; 2. LNG Pricing

1. Introduction/Background

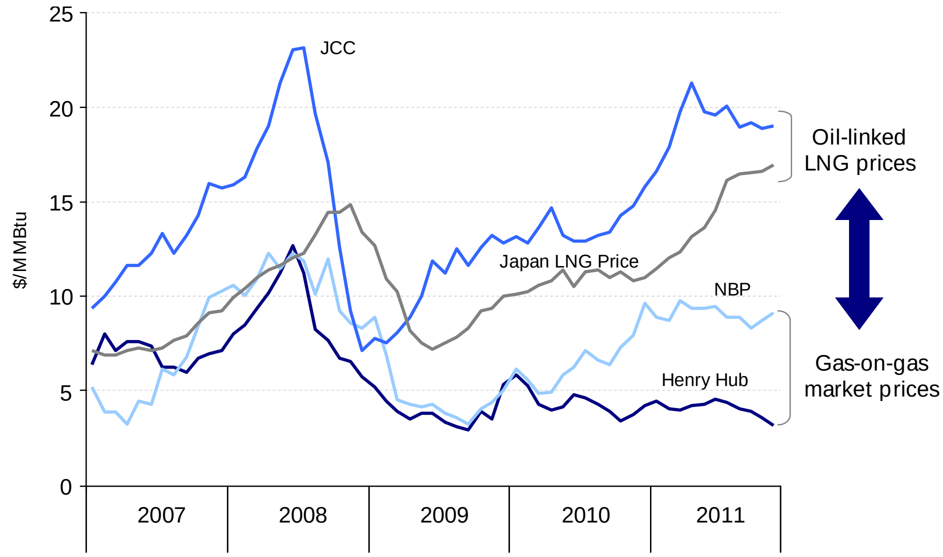
The global LNG market is experiencing a large and sustained regional price divergence due to differences in long-term contract pricing mechanisms. Asia remains a predominantly oil-linked LNG market. Continental Europe remains a mixture of oil product-linked and hub-priced natural gas markets. The UK and North America have established gas-on-gas market pricing mechanisms, represented by National Balancing Point (NBP) and Henry Hub (HH), respectively. North American gas price levels have been sustainably trading at large discounts against other natural gas prices globally due to the boom in domestic shale gas production. LNG trade remains predominantly long-term in nature – spot trade and short-term contracts only capture around 15% to 20% of the total LNG global trade, a quantity not large enough to arbitrage differences and drive global natural gas price convergence.

<Regional long-term contract pricing structure>



Source: Poten & Partners

<Resulting regional price levels>



Source: Poten & Partners

The current North Atlantic gas-on-gas price discount to oil indexed LNG prices in Asia is tempting Asian buyers to the idea of a portfolio of pricing mechanisms to lower cost and diversify exposure to any one mechanism. As of early 2012, two Asian buyers in India (GAIL) and South Korea (KOGAS) have agreed to purchase long-term contracts linked to HH from Cheniere's Sabine Pass, a US Gulf Coast LNG export project. Would the increase in LNG exports from North America to Asia, potentially introducing gas-on-gas market pricing, cause Asian LNG price to materially delink from oil indexation? Would HH or NBP linkage be an established pricing mechanism in Asian LNG market in a foreseeable future, creating a two-tier pricing mechanism? Furthermore, if "*a foreign*" HH or NBP reference marker for price indexation in Asian long-term contracts were not to prevail, would a local Asian gas-on-gas market price develop and create a two-tier pricing system?

2. Objective

The objective of this paper is to discuss the potential impact of long-term contracts linked to non-Asian gas-on-gas market prices, such as HH, on the traditional oil linked price mechanism in Asia. Furthermore, we will discuss whether a competitive and liquid natural gas hub can develop locally within Asia. We will discuss whether such a future gas hub could offer an alternative pricing mechanism to oil linkage in Asian LNG long-term contracts.

3. Discussion

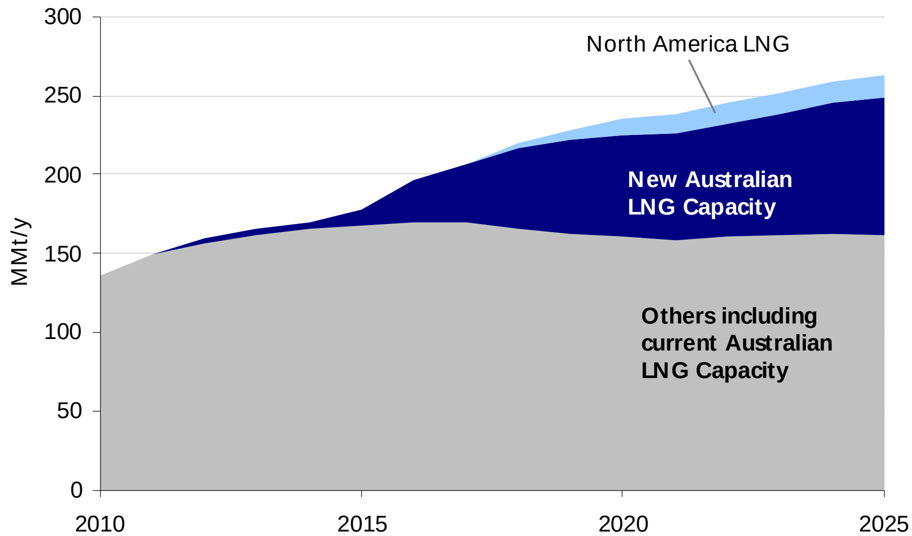
A. "*A foreign*" gas-on-gas market price contract impact in Asian LNG contracts

The North American shale gas boom has changed the landscape of the US gas market – it is shifting from an LNG importing play to potentially an LNG exporting one. The current North American price discount to oil indexed LNG prices in Asia is tempting Asian buyers to consider having some exposure to non-oil price indexation. In early 2012, Indian and Korean buyers agreed to purchase a total of 7 MMt/y from the US Gulf Coast beginning as early as 2015. More LNG linked to gas-on-gas market prices could be purchased by Asian buyers. LNG sellers on the US Gulf Coast may prefer hedging feedgas risks by selling at HH linked price rather than selling at oil indexed pricing. This is the approach taken for LNG sales so far, all made by Sabine Pass. While GAIL and KOGAS have accepted HH linked LNG pricing, they have done so at a discounted price to a traditional oil linked price.

(i) Limited share in the growing Asian LNG market

Even if the 15 to 20 MMt/y of LNG exports that we project from North America is all sold in Asia using gas-on-gas hub pricing, this will only represent 6% to 9% of the total Asian demand of 235 MMt/y in 2020. Most of the supply contribution will actually come from Australia, a very expensive place to develop LNG and upstream infrastructure, and where HH linkage would not support project economics. North America's contribution to the overall Asia Pacific supply demand balance will not be sufficient to fundamentally break the oil price linkage in Asia Pacific. There could be an indirect impact on oil linked pricing – i.e., lower slope to oil price and greater adoption of S-curve structures, as supply competition increases, assuming that HH linked LNG volume continues to be more competitive than oil-linked LNG prices. Furthermore, one innovative approach could be a blending of oil-linkage and gas-on-gas market prices. This ultimately will come down to negotiations between buyers and sellers, taking into account the LNG project's economics.

<LNG supplies into Asia – Increasing but limited share of North American LNG >

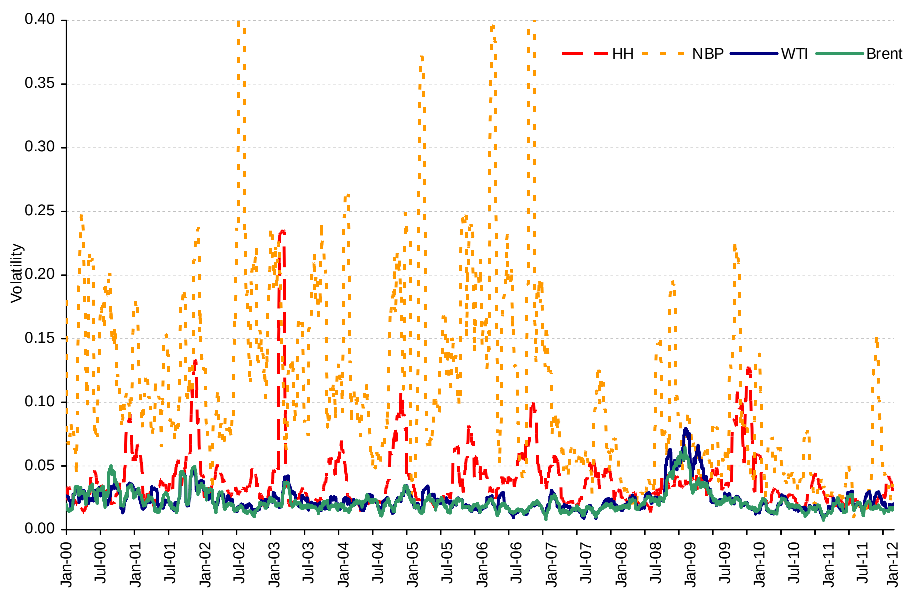


Source: Poten & Partners

(ii) Less HH price volatility vs. challenging cost structures for green field projects in Asia Pacific

HH price volatility has decreased in recent years due to abundant domestic shale gas production. However, several Asian LNG players are still hesitant to fully endorse HH and NBP as mainstream LNG pricing mechanisms due to their potential long-term price volatility. In addition, some players fear that security of supply could be jeopardized if supply projects do not develop on a timely basis because alternative pricing mechanisms are adopted rather than an oil linkage. Suppliers prefer the traditional oil linkage to support the economics of ever more complex and expensive liquefaction projects.

<Volatility of Henry Hub, NBP, WTI, and Brent prices>



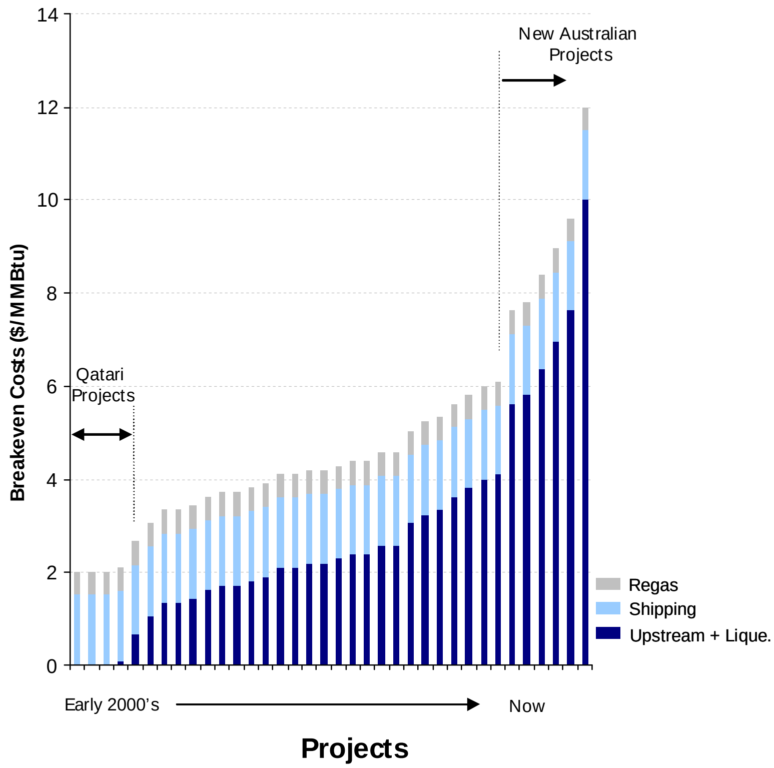
Source: Poten & Partners

Very large capital investment is required to support new liquefaction infrastructure. Investors in this new infrastructure will need to secure long-term commercial arrangement to underpin project returns and financing. The main challenge facing supply projects worldwide has been cost. The average project today is more than twice as expensive as in the early part of the last decade, and in many cases much more expensive. The explanations are many and various – high raw materials, limited contractor pool, insufficient qualified engineering resources and fast-rising labour costs for skilled resources, broader and more costly scope in projects (such as difficult gas compositions, higher cost locations and large infrastructure costs).

Pricing long-term SPAs, that anchor the development of an LNG export project, against volatile NBP, or depressed HH, would be difficult. This could hamper and delay the development of projects. Reflecting on this reality, Asian buyers are actively participating in the upstream and liquefaction segments of the LNG value chain. Supply project sponsors have been pushing to maintain oil-linked pricing to make projects economic.

Breakeven delivered costs over the last decade have risen from around \$2/MMBtu for the Qatari mega trains to \$10/MMBtu or more for some of the recent Australian projects. Asia Pacific suppliers will continue to insist on oil linkage to make these projects economic to develop, anything less they argue would stop developments or push development resources and investment into alternatives such as oil exploration and production.

< LNG Project Breakeven Cost Curve>



Source: Poten & Partners

We believe oil price indexation will remain the main factor in pricing long-term Asian LNG contracts even though an element of HH linked indexation may creep into pricing. From a structural perspective – i.e., given the regionally fragmented natural gas markets – a substantial shift to long-term HH or NBP pricing in Asia is still many years away.

B. Asian gas-on-gas market price indexation?

If "*a foreign*" HH or NBP reference marker for price indexation in Asian long-term contracts was not to prevail, would a local Asian gas-on-gas market price develop and create a two-tier pricing system?

(i) Physical connectivity and deregulation process are necessary to create natural gas hub

If the existing gas-on-gas markets, such as US, the UK and Northwest European gas markets, were to provide a guideline, important factors for Asia to develop an effective, liquid, transparent and trusted gas-on-gas marker price are as follow:

- Growing domestic production
- Growing pipeline imports and exports

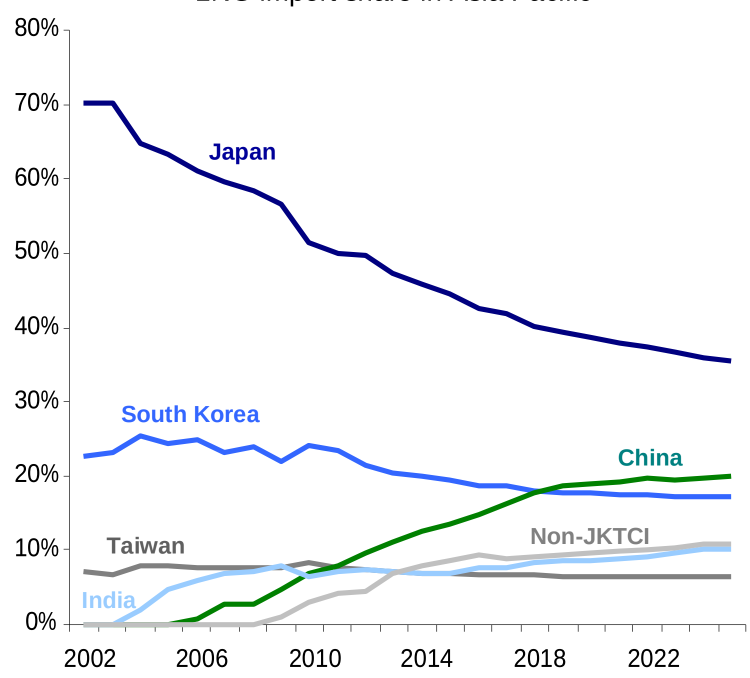
- Interconnected gas transmission pipeline system
- Substantial storage capacity
- LNG trade (in case of UK and Northwest Europe)
- High liquidity
- Steps towards deregulation, including in natural gas upstream, transportation and trading
- Transparent market with limited government intervention
- A large and efficient futures market with many buyers and sellers competing for positions.

Currently there is no gas market in Asia that would clearly qualify for competitive hub pricing development. We will discuss which Asian LNG market could potentially meet the criteria longer-term.

(ii) Changing landscape of Asian LNG market

Historically, the Asian LNG market was led by traditional buyers in Japan, South Korea, and Taiwan (JKT). After Japan's tragic earthquake/tsunami in March 2011, followed by multiple nuclear power plant shutdowns, the importance of LNG as a source of power generation had been confirmed. In 2011, JKT had Asia Pacific market shares of 50%, 23%, 8%, respectively, while China's was only 8%. However, China's LNG demand will grow steadily throughout the decade and China's LNG market share will increase to 20% of Asia Pacific by 2025, whereas JKT will decrease to 36%, 17%, and 6%, respectively. Asian niche markets as an aggregate (e.g., Malaysia, Indonesia, Thailand, Singapore and others) will also increase its presence from 4% in 2011 to 11% in 2025. We are entering an era of more diverse LNG buyers in Asia Pacific with China's increasing presence.

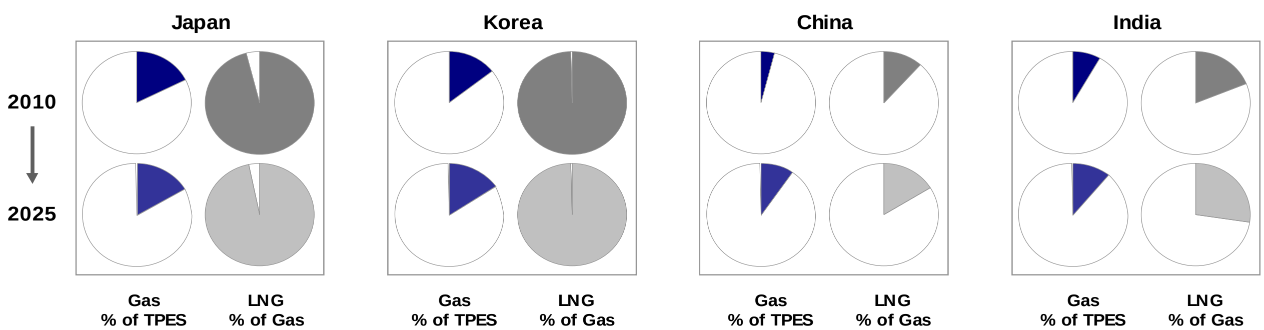
<LNG import share in Asia Pacific>



Source: Poten & Partners

Interestingly, even with China's increasing presence in Asia's LNG market, LNG is still a small part of the country's natural gas supply portfolio; from 13% in 2011 to 19% in 2025. This characteristic points to a diverse natural gas supply portfolio for China, and a potential for a dynamic market with multiple physical sources. In this respect, China will stand out amongst competing Asian countries. JKT are projected to remain almost exclusively dependent on LNG as a source for natural gas. All three countries are isolated from nearby production, and very hard to access through pipeline because of geographical and political drivers. All three do not possess potential for domestic gas development and are projected to depend on imports to feed their growing natural gas needs. India, with no access to pipeline imports, and a struggling domestic production, will increase its reliance on LNG.

<Natural gas & LNG share in the energy mix of major Asian countries >



Source: Poten & Partners, IEA, EIA

(iii) Case Study: China – a "unique" LNG/natural gas market emerging in Asia

China is different from traditional JKT markets in that it has three major categories of supply source for natural gas – domestic production, pipeline gas imports and LNG imports. Its domestic natural gas production reached 101 Bcm in 2011, a 7% increase from the previous year, and pipeline imports reached 14 Bcm and LNG imports 16 Bcm in 2011. China's natural gas consumption was 130 Bcm in 2011, 21% increase from 2010. By 2025, consumption could grow to be as high as 400 Bcm. China is increasing pipeline transmission networks, connecting West to East and between the Eastern coastal provinces. Major domestic pipelines are the West-to-East Pipelines I and II, and the Sichuan-to-East pipeline. International pipeline networks are Turkmenistan-to-China, Kazakhstan-to-China, Myanmar-to-China and potential pipelines from Russia. With this influx of pipeline gas, China will still increase LNG import volume in absolute terms but the ratio of LNG in its natural gas supply mix will only modestly increase from 13% in 2011 to 19% in 2025.

Favourable Physical Fundamentals

China has fundamental factors similar to gas-on-gas markets in North America – growing domestic production (both conventional and unconventional), pipeline and LNG imports. Although there are many questions about how easy it is to extract shale gas in China, US Energy Information Agency (EIA) has estimated that China's two basins – Sichuan and Tarim – could hold 1,275 Tcf of risked recoverable resources, the largest in the world. These physical characteristics establish the potential for China, among selected Asian countries, to develop a gas-on-gas market. But it will take more than just conducive physical characteristics to drive true market reforms and for the development of meaningful gas-on-gas competition to develop.

<Natural gas production, imports and exports, and consumption in 2010>

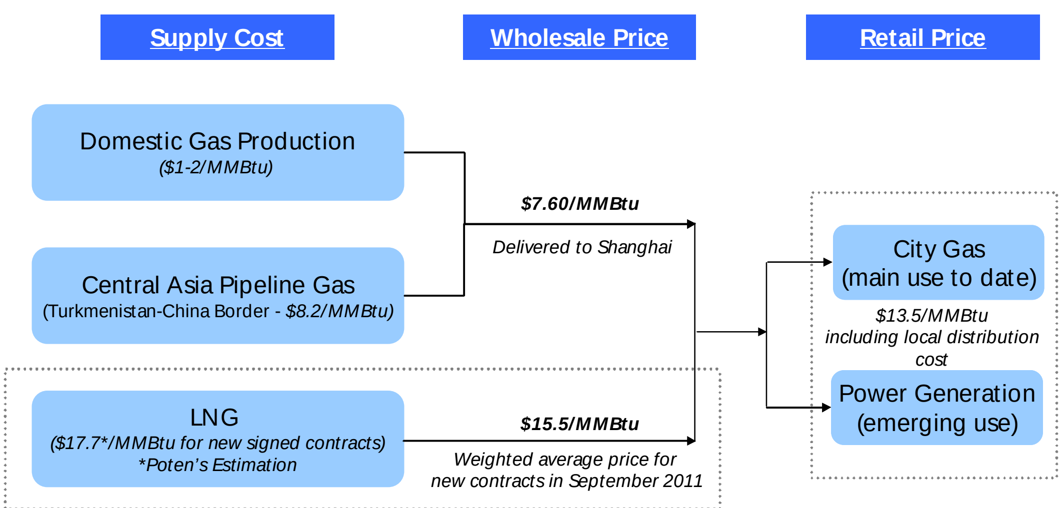
	US	UK	China	Japan	South Korea	India
Proved reserve (Tcf)	273	9	99	Minimum	Minimum	51
Technically recoverable shale gas resources (Tcf)	862	20	1,275	-	-	63
Domestic production (Bcf/d)	59	6	9	Minimum	Minimum	5
Pipeline imports (Bcf/d)	9	3	0	-	-	-
Pipeline exports (Bcf/d)	-3	-2	-	-	-	-
LNG imports (Bcf/d)	1	2	1	9	4	1
LNG exports (include. re-export) (Bcf/d)	-0	-	-	-	-	-
Domestic consumption (Bcf/d)	66	9	11	9	4	6

Source: Poten & Partners, BP Statistics, EIA

Market-oriented Gas Pricing Reforms in Southern China – Only a First Step

While physical conditions for a gas-on-gas market could emerge in China, the deregulation process to establish a liberalized, competitive, transparent and liquid gas market is still at its infancy. At the end of 2011, the Chinese government started natural gas pricing "pilot" reform in Southern China's Guangdong Province and the Guangxi Zhuang Autonomous region. This is the first real effort to reform domestic gas prices, and introduce a new pricing mechanism, to address the issue of price mis-match between imported and domestic gas. Lower domestic gas prices compared to higher imported gas prices can leave gas importers suffering losses or requiring subsidies.

<Current pricing misalignments>



Source: Poten & Partners, various sources

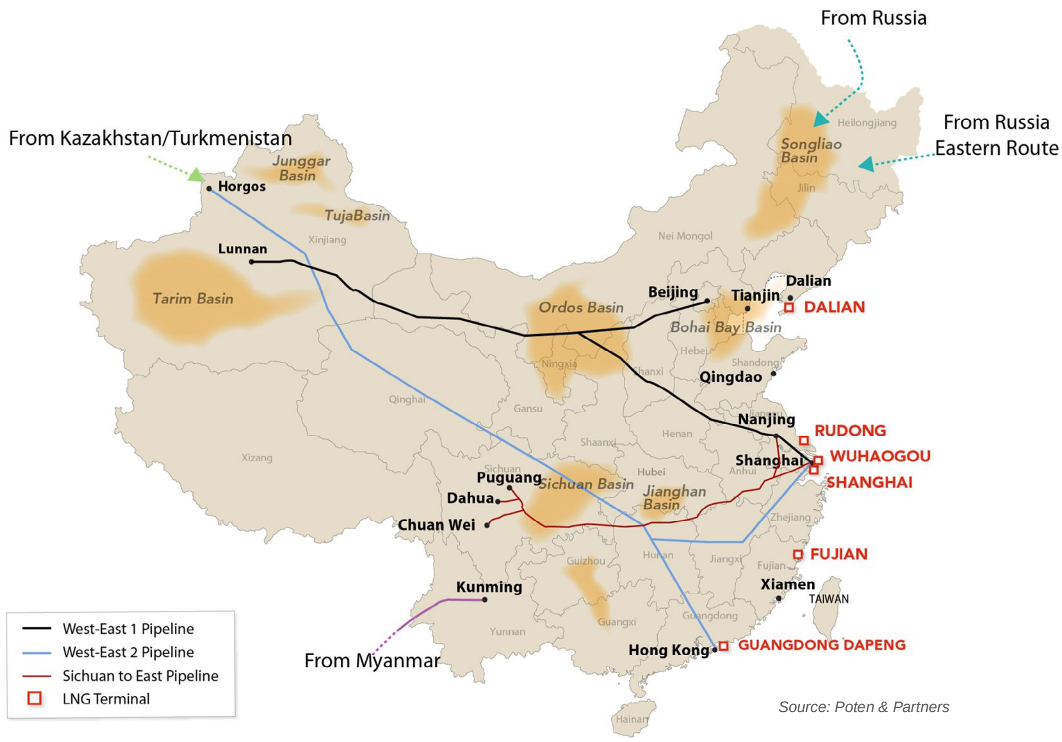
Currently, the end-user natural gas price is set by the government. The goal for this pilot reform is to allow natural gas prices in the two pilot regions to fluctuate along with competing substitute fuels, at a discount to promote gas use. The government will still set the transmission fee of natural gas pipelines. Under this method, the natural gas prices will be pegged to that of alternative energies (fuel oil used in factories and LPG in households), using the netback calculation method. Shanghai prices of fuel oil and LPG were selected as the benchmark prices for Guangdong and Guangxi. However, price caps have been set in the two regions – RMB 2.74/m^3 (about \$10.82/MMBtu) in Guangdong, and with RMB 2.57/m^3 (about \$10.31/MMBtu), taking into account ex-factory prices and pipeline fees. These caps will soften the impact of these new regulations and the price change will be limited.

Whether the trial program will be rolled out to other import dependent regions – particularly coastal provinces like Shanghai, Tianjin and Fujian – remains to be seen. But China eventually aims to liberalize ex-factory gas prices to enhance efficiency and promote the development of China's prodigious reserves of unconventional gas including CBM and shale. The key question is "Can the Chinese gas market develop to become similar to, for example, the North American gas market and provide a potential pricing benchmark for Asian gas and LNG markets?" We are seeing some signs of regional market reform process taking place in China, but these are still early, small steps. It is very difficult to estimate whether this reform process will widen in scope and reach other regions in China.

Candidates for a competitive and liquid market in China

There are some signs that the Shanghai area could develop as a gas hub. As mentioned, the latest pilot program selected Shanghai prices – fuel oil and LPG – as the benchmark prices for Guangdong and Guangxi. Shanghai is a large natural gas demand centre and it is linked to multiple gas supply sources – West-to-East Pipelines I and II, Sichuan to East, offshore Pinghu gas field, LNG imports at the Shanghai terminal. Another hub candidate is Guangdong – it is in Southeast China at the end of the West-to-East Pipeline II from northwest China, there is offshore production from the Liwan field and other potential discoveries, and LNG imports to the Guangdong and other planned terminals, in an area adjacent to the Hong Kong financial market. More natural gas related infrastructure needs to be built in order to create a gas hub. Ideally, there would be more connectivity among various demand centres in China, such as between Shanghai and Guangdong.

<China's natural gas infrastructure and a potential gas hub >



Source: Poten & Partners

(iv) Insights from US and UK gas hub developments

China has the potential physical characteristics and is just beginning the market reforms necessary to create a gas-on-gas market. However, if the US and the UK were to provide any guidance, a number of structural changes were required in the gas industry as both countries pursued deregulation in natural gas markets beginning in the late 1970s. It was these changes that facilitated the creation of North American and UK gas pricing hubs, but the road to reach significant market liberalization has been long. It required thirty to forty years of deregulation process, some times involving privatization and the significant challenges involved in unbundling of vertically integrated gas organizations in the process.

US natural gas market deregulation process started 1970s from unbundling

- 1970s – Natural Gas Policy Act put Federal Energy Regulatory Commission (FERC) in charge of intrastate and interstate natural gas production in 1978.
- 1980s – US began a process of un-bundling the natural gas business by eliminating take-or-pay clauses from gas supply agreements to create more competition among natural gas suppliers.
- 1990s – Pipelines and other facilities, including LNG terminals, were transformed into capacity service providers through requirements for Open Access, to achieve de-regulation. In 1991, Henry Hub started to be used as NYMEX trading price.

- HH is the most liquid and transparent natural gas trading hub in the world, and is the benchmark upon which US imported LNG is priced.
- The US gas industry is still not fully liberalized. Residential consumers still buy from local utilities that own the distribution network and have monopoly rights.

UK natural gas market deregulation process started 1980s with privatization

- 1980s – Liberalization began with the Natural Gas Act in 1986, which set the necessary regulatory framework. Before 1986, British Gas operated as the publicly owned, vertically integrated transporter and supplier of natural gas in the UK.
- 1990s – British Gas was split into Centrica (gas retail and distribution) and BG plc (upstream, transmission and storage) in 1997 and then split again in 2000 when Lattice was established (transmission – now National Grid). Resale of pipeline capacity amongst shippers was allowed in 1996. Competition created the conditions for spot prices to evolve – NBP started in 1996 and is now the pricing benchmark for gas in the UK.
- UK gas is traded for delivery in the future, allowing players to hedge positions.
- Gas is completely unbundled with all consumers able to buy from competing suppliers and the physical infrastructure provided as a service.

The experience of the US and the UK shows that the road to implementing true and effective natural gas market liberalization is long and fraught with challenges. It took decades for both countries to finally “get it right”, despite having dynamic gas industries with substantial domestic production and pipeline connectivity. As discussed above, China has just now embarked on implementing limited pricing mechanism changes in few pilot regions.

(v) Back to the Asian LNG context – Security of supply remains key driver for Asian long-term trade

One fundamental premise is that security of supply cannot be jeopardized by an Asian gas-on-gas market hub development. Asian buyers are renowned for their strong focus on security of supply in their long-term LNG procurement. The high prices for LNG in Asia therefore reflect the geographic isolation and scarce indigenous energy resources of the traditional Asian LNG buying countries. Asian buyers have an overriding concern with security of supply as compared to price sensitivity and are willing to pay a premium for a reliable supply source.

Asian buyers may be reluctant to overly rely on a nascent illiquid hub located in Asia. Some may indeed seek diversification and accept a certain level of exposure to North American prices (such as the latest KOGAS and GAIL 3.5 MMt/y deals with Sabine Pass in the US), but this will remain more of a marginal diversification tool than a new mainstream pricing mechanism. As discussed earlier, potential Chinese gas hubs will take decades to develop as transparent, deep and reliable benchmarks by all the buyers and sellers of LNG in Asia Pacific. NBP remains too volatile to anchor a long-term LNG supply agreement (see volatility graph above). HH even with less volatility than previous years due to the shale gas revolution remains uncertain in the long-term.

In this environment, oil remains the most transparent and trusted mechanism of pricing LNG long-term in Asia. It is more a question of exactly how the oil linkage is set rather than will there be an oil linkage. Players have a lot at stake in the LNG chain, whether it is multi-billion supply projects, a downstream gas/electricity market that needs high reliability levels, and infrastructure developers requiring certainty before building expensive and complex projects. We view that solid partnerships between suppliers and buyers through out the LNG value chain will be vital for any complex LNG projects to be developed.

4. Conclusion Summary

We are in a very interesting and exciting moment in time. Driven by the shale gas revolution in North America, we could be seeing further North American LNG volumes targeting Asia Pacific. However, in the context of a robustly growing Asian LNG market, gas-on-gas market derived pricing in long-term contracts will not become a common indexation element. The largest contributor of LNG supply to the Basin will be Australia, a country challenged by high cost and limited labour resource availability. The development of overly complex and expensive LNG supply projects in the Basin will require a higher price level than current depressed North American prices provide. A "*foreign*" gas-on-gas market price impact on Asian LNG market will be limited and indirect – there will be limited delinking from oil price indexation. Forty years of Asian LNG industry tradition will be resistant to change.

In our view it will take more than a decade for Asia to develop any "*indigenous*" gas-on-gas market pricing mechanism, along the lines of HH and NBP. We have identified China as the most likely place for a natural gas hub to develop in Asia but several challenges remain – further deregulation, transparency and competition in the market, more players and liquidity. It may take even longer for such hubs to gain the full trust of Asian LNG buyers and sellers to a degree where they will feel comfortable using it as a long-term LNG benchmark price. In conclusion, oil-linked pricing will remain as the primary long-term contract pricing indexation methodology in Asia, especially for new LNG supply projects to achieve Final Investment Decisions. The emergence of a genuine Asian gas hub in the global LNG market will take a long time.