Recent moves towards gas trading hubs in Asia: implications for Asian gas buyers and sellers

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In January 2016, the Singapore Exchange (SGX) announced that Trafigura and Pavilion Gas made the first trade of a derivatives contract using the FOB Singapore SGX LNG Index Group (SLInG) price index. The announcement comes against a backdrop of growing interest in developing natural gas trading hubs in Asia. Both China and Japan recently have established gas/LNG trading platforms in Shanghai and Tokyo respectively.

The emergence of gas trading hubs (physical or virtual) has the potential to transform Asian natural gas markets. In Asia, natural gas in the form of LNG traditionally has been bought and sold under long-term sale and purchase agreements (***SPAs***) at an oil-indexed price. The significance of a gas trading hub is that, if it develops sufficient liquidity, it might establish a "market price" for natural gas and thereby call into question the appropriateness of oil-indexed pricing models. The emergence of such hubs may also impact procurement patterns of Asian buyers, with a shift towards more short-term and spot LNG purchases and attempts by buyers to obtain greater contractual flexibility.

The European experience demonstrates the potentially far-reaching implications of the development of gas trading hubs. In Europe, gas traditionally was bought and sold under long-term, oil-indexed SPAs. That changed with the emergence of gas trading hubs. As liquidity at those hubs increased, so too did the confidence of natural gas market participants in the traded price published at those hubs. This led to the development of a "market price" for natural gas, a wave of price negotiations under long-term SPAs as buyers sought to align the price they paid for gas under their long-term contracts with the new "market price", and, eventually, the transition to contractual pricing models that reflect both oil- and gas-indexed pricing. Although it is too early to determine whether that transition is complete, the impact of gas trading hubs in Europe is undeniable.

A similar transformation is possible in Asia, should liquid gas trading hubs emerge, although some obstacles remain. In the short term, market participants should monitor closely the development of the different potential Asian gas trading hubs. As the recent European experience demonstrates, the development of liquid gas trading hubs has the potential to significantly transform Asian natural gas markets.

The European experience

The reaction of European market participants to the emergence of liquid natural gas trading hubs is instructive. Previously, most pipeline gas and LNG was imported into Europe under long-term import contracts with oil-indexed price formulae, but during the 2000s, several natural gas trading hubs emerged (*i.e.*, the National Balancing Point (NBP) in the United Kingdom, Zeebrugge in Belgium and the Title Transfer Point (TTF) in the Netherlands).

The emergence of liquid trading hubs in Europe was facilitated by two key developments.

First, European regulators took steps to develop gas-on-gas competition. Regulators opened up third-party access to the gas transmission and distribution assets and pushed to unbundle vertically integrated companies. The European Commission (***EC***) also declared that contractual provisions that limited or prohibited the resale or diversion of LNG or gas (*i.e.*, destination restrictions) violated EU competition law. In addition, competition authorities declared that full-supply long-term contracts (*i.e.*, contracts for supply of all of the gas to be bought by a customer, often for ten years or more) violated national and EU competition laws. This meant that contracts entered into between European importers and producers no longer mirrored contracts between those importers and their customers at the wholesale level. As a result, not only did competition for customers increase between the different importers, but customers also were free to purchase natural gas on more favourable terms as they became available.

Second, market conditions led to a published price at gas trading hubs that was significantly lower than the price under long-term oil-indexed contracts. Following the global financial crisis, European demand for natural gas slackened. At the same time, the shale gas revolution meant that the US became a less attractive market for LNG cargoes, and producers responded by diverting large volumes of gas intended for the US to Europe. As a result, greater volumes of gas became available on European trading hubs and spot gas hub prices were as much as 20-30 percent lower than oil-indexed prices, leading to mounting losses for some importers locked into long-term oil-indexed contracts.

As a result of these market conditions, price renegotiations were initiated under nearly all long-term import contracts. Although the outcome of most of these price renegotiations is confidential, market commentators estimate that as much as 50 percent of natural gas volumes imported into Europe under long-term import contracts has been re-priced by reference to the prices set by European gas trading hubs.

An Asian gas trading hub—the leading candidates

<u>*Singapore—the IEA's anticipated front-runner*</u>

The International Energy Agency has identified Singapore as the most likely candidate to establish a successful gas trading hub in Asia. This primarily was due to its deregulated pricing model, the structural separation of gas retailing and transportation activities, and third-party open access to key infrastructure. The SGX's recent launch of the SLInG pricing index provides further cause for optimism. The SLInG currently is based on average weekly assessments for LNG cargoes in the vicinity of Singapore gathered from a group of producers, consumers and traders, but will eventually move to daily assessments.

In the US and Europe, gas pricing points have been established successfully as physical or virtual points. There are two main challenges for the creation of a physical pricing point in Singapore (in contrast to a virtual pricing point such as the SLIng):

There presently is no integrated pipeline network within Southeast Asia, and the existing Indonesian and Malaysian pipelines only flow gas into Singapore. The Singapore gas market therefore deals with relatively small volumes, which presumably explains why the SGX has promoted the use of a virtual pricing point (similar to the NBP in the United Kingdom and the TTF in the Netherlands) rather than a physical one.

The local Singapore gas market remains subject to regulations that arguably inhibit the development of full gas-on-gas competition, including a moratorium on new pipeline imports until the earlier of 2018 or when LNG imports reach 3 million tonnes per annum (***MTPA***), and an aggregator licencing scheme that accords licensees exclusive right(s) to import LNG into Singapore to sell such LNG as LNG or regasified LNG to potential end-users in Singapore.

Singapore therefore may have more promising prospects to develop a gas trading hub around a virtual LNG pricing point. However, the SLInG is new and it is unclear, for now, how successful it will be. A key function of the SLInG's potential success will be the number of market players involved in the price assessment process and how effectively the SGX polices the process—that will only become evident over time.

On a broader level, however, while Singapore may be well-placed to develop a pricing point for the Southeast Asian gas market, the North Asian market arguably has its own unique characteristics (*e.g.*, summer/winter seasonal fluctuations in gas demand) and may be better served by a trading hub and pricing point located in a North Asian country. In this respect, China and Japan are moving forward with plans to develop their own gas trading hubs. Both jurisdictions have much larger domestic natural gas markets than Singapore, which is likely to be an advantage in developing liquidity.

Japan—the world's largest LNG importer

Japan is the world's largest consumer of LNG with imports in 2015 of approximately 85 MTPA.

Most LNG imported into Japan is currently priced with reference to the imported price of crude oil (*e.g.*, the "*Japan Crude Cocktail*" (JCC)). However, there are some signs that the Japanese market may be moving towards the development of both a gas hub and an LNG/gas price index. The Japan OTC Exchange, supported by Japan's Ministry of Economy, Trade and Industry, already has begun offering non-deliverable forward LNG contracts, with the first such deal reportedly executed last year.

At the same time, Japan is taking measures to liberalise its energy market and also to promote greater access for more participants. In April 2016, Japan liberalised the electricity retail market and it is expected that a full liberalisation of the gas retail market will follow by April 2017. Separately, there are also early plans by the Japanese Government for three leading gas companies (which together account for more than 70 percent of retail gas sales in Japan) to separate their pipeline transportation activities from their retail activities, albeit that the exact form of unbundling has not yet been decided (*e.g.*, whether the pipeline business will be transferred to an affiliated company or be transferred to an independent company outside of the corporate group).

China—a growing gas market

Natural gas imports into China reached approximately 20 MTPA in 2015, and while there has been a recent dip in gas consumption, that number is projected to rise over the longer term as domestic demand increases and greater reliance is placed on cleaner fuels such as gas. There are a number of proposed gas trading platforms and plans to trade gas futures contracts in China. For example, Xinhua News Agency and the National Development Reform Commission have cooperated in establishing a natural gas trading platform in Shanghai. At the same time, there has been ongoing effort in China to promote limited third-party access rights to pipeline networks and LNG terminals (*e.g*., third-party access right to Chinese terminals, subject to overall needs of supply security), which would be a first step to allowing gas-on-gas competition to develop. However, gas prices in China remain largely subject to regulation, but with some early signs of liberalisation and, recently, more scope for buyer-seller negotiation to set the gas price (*e.g.*, industry players will be allowed to charge up to 20 percent more than government benchmark prices with no downward limit for price fluctuations).

One common characteristic of the Japanese and Chinese gas markets is the predominance of vertically-integrated companies (mainly State-owned in the case of China) that import LNG, own the physical infrastructure (*i.e.*, the LNG terminal and natural gas pipelines) necessary for receipt of LNG and/or natural gas. In practical terms, this means that there may be a high barrier to gas-on-gas competition as companies that wish to import gas on their own may be required to invest and own their own infrastructure. As mentioned above, however, there are moves in both countries to open up to third-party access to physical infrastructure in the hope that will in turn promote liquidity in the market. The extent to which such efforts prove successful likely will be a key determinant of how quickly either country will be able to develop a liquid Asian gas trading hub.

Where to next?

Asian gas trading hubs are in the early stages of development. However, supply and demand fundamentals suggest that some of the market conditions necessary for the development of liquid gas trading hubs are already in place.

There is a material divergence between spot and long-term LNG supplies in Asia, with spot LNG prices hovering around US$4-5 per MMbtu while long term oil-indexed LNG is in certain instances 50 percent or more higher as a result of relatively higher pricing slopes negotiated in earlier years. Media reports suggest that Asian buyers are responding to this spread by seeking to renegotiate the price or volumes under their LNG SPAs (*e.g.*, Petronet refusing to take its volume commitment under a take or pay contract with Rasgas and negotiating a pricing discount).

The outlook going forward is mixed. Some market commentators suggest that there is likely to be an oversupply of natural gas with a number of export projects expected to commence delivery over the next few years. This would put pressure on pricing mechanisms in existing long-term Asian natural gas contracts. But other commentators take the view that low oil prices may lead to the deferment of final investment decisions for some projects and expect a corresponding rebound in LNG prices by the end of this decade.

One key development that will be critical if Asian gas trading hubs are to set the price for natural gas in the region is a concerted push by regulators fully to liberalise national gas markets. This highlights a key difference between the European and Asian gas markets—unlike Europe, Asia does not have an equivalent to the EC to establish common regulatory standards for third party access to pipeline infrastructure or to standardise requirements for competition (*e.g.*, by outlawing of destination restrictions). As a result, the liberalisation of the Asian natural gas markets is likely to take longer than in Europe and occur on a more *ad hoc* basis.

The lesson for Asian natural gas buyers and sellers from the European experience is that, if a reliable gas hub price develops that decouples from oil-linked contract price, buyers are likely to use any available legal or commercial leverage to renegotiate their long-term contract pricing. For that reason alone, natural gas buyers and sellers would be well-served to monitor closely the potential development of gas trading hubs in Asia.