WILL LNG EXPORTS FROM NORTH AMERICA / EAST AFRICA DRIVE GLOBAL PRICE INTEGRATION?

Kyoichi Miyazaki
LNG & Gas Senior Consultant
kmiyazaki@poten.com
Majed Limam
LNG & Gas Senior Consultant
mlimam@poten.com
Poten & Partners Inc., New York

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ABSTRACT
The global LNG market is experiencing a large 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 (National Balancing Point and Henry Hub). North American gas price levels have been trading at large discounts to other natural gas prices globally due to growing shale gas production. These gas prices are opening opportunities for US LNG exports and are tempting Asian buyers to consider Henry Hub linked pricing mechanisms to lower cost. North American exports, together with exports from emerging supply regions such as East Africa, could have a substantial impact on the global LNG supply picture and hence prices later this decade. Poten will discuss the key issues associated with how global pricing integration could take place - or not - focusing on the potential evolution of Asian pricing mechanisms due to the impact of new supply sources:

Would the increase in LNG exports from North America and East Africa cause Asian LNG prices to materially delink from oil indexation?

Would new pricing mechanisms - anywhere between a traditional oil-linkage and a Henry Hub linkage - emerge?

Would Henry Hub prices plus costs of liquefaction and delivery to Asia set a floor for Asian pricing?

Can a local Asian gas-on-gas market price develop as an alternative base for pricing LNG in Asia?

1. INTRODUCTION / BACKGROUND
The global LNG market continues to experience a large regional price divergence due to differences in long-term contract pricing mechanisms. Asia remains a predominantly oil-linked LNG market with some Henry Hub-linked deals signed but not yet active. 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 (National Balancing Point and primarily Henry Hub). At the same time, LNG trade remains predominantly long-term in nature – true spot trade only captures around 2% to 5% of the total LNG global trade, a quantity not large enough to arbitrage differences and drive global natural gas price convergence.
North American gas price levels have been trading at large discounts to other natural gas prices globally due to growing shale gas production. These large discounts are opening opportunities for US LNG exports and are encouraging Asian buyers to seek Henry Hub linked pricing mechanisms to lower the cost of LNG. North American LNG exports, together with exports from other emerging supply regions such as East Africa, could potentially have a substantial impact on the global LNG supply picture and hence prices later this decade.

The current margin between North American gas-on-gas and oil indexed LNG prices in Asia is encouraging Asian buyers to build a supply portfolio with different pricing mechanisms to lower cost and diversify exposure to any one mechanism. In early 2012, two Asian buyers, South Korea’s Kogas and India’s GAIL, agreed to long-term contracts linked to HH from Cheniere’s Sabine Pass, a US Gulf Coast LNG export
project. This was followed by Japanese trading houses (Mitsubishi, Mitsui & Co., Sumitomo) and utilities (Tokyo Gas, Chubu Electric, Osaka Gas) entering three US LNG export projects (Cameron LNG, Cove Point LNG, Freeport LNG) by acquiring liquefaction capacity. Other Asian LNG players could follow, whether as offtakers or by entering LNG projects as equity investors or tolling facility capacity holders. Asian buyers are also hopeful of obtaining LNG from East Africa, where a string of gas discoveries offshore Mozambique is estimated to hold a minimum of 100 Tcf of gas resources (Source: Anadarko and ENI). This region will provide yet another major opportunity to diversify Asian buyers’ supply portfolio’s – i.e., locational and potentially pricing diversification. An intriguing question emerges – Will new LNG suppliers from North America and East Africa drive global gas price integration?

2. OBJECTIVE

The objective of this paper is to discuss the key issues associated with how global gas pricing integration could take place – or not – focusing on the potential evolution of Asian pricing mechanisms due to the impact of new supply sources: Would the increase in LNG exports from North America and East Africa cause Asian LNG prices to materially delink from oil indexation? Would new pricing mechanisms – anywhere between a traditional oil-linkage and a Henry Hub linkage – emerge? Can a local Asian gas-on-gas market price develop as an alternative base for pricing LNG in Asia?

3. DISCUSSION

The North American shale gas boom has changed the landscape of the US gas market – it has shifted from an LNG importing play to an LNG exporting one. The current North American price discount to oil indexed LNG prices in Asia is about 80% (2012 average about $14/MMBtu) and is driving Asian buyers to seek 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. Several Japanese trading houses and utilities followed by entering three US LNG export projects (Cameron LNG, Cove Point LNG, Freeport LNG), adding up to over 14 MMt/y of production capacity. These Japanese LNG players are anxiously waiting for US Department of Energy approval for non-FTA status to these export projects so that they can import LNG directly to their home markets. East Africa (e.g., Mozambique with gas reserve of over 100Tcf) has also become another major frontier supply region for Asian buyers to consider.

KEY STATEMENT 1: Asian buyers more comfortable with decreasing HH price volatility but remember large historical variations

HH price volatility has decreased in recent years due to abundant domestic shale gas production. Many Asian LNG players are becoming cautiously optimistic about the future of HH price volatility and are taking HH-linkage seriously as a mainstream LNG pricing mechanism. HH volatility (defined as the standard deviation of the natural log of monthly prices) has been below 0.05 between early 2010 and the end of 2012. Oil price volatility (Brent and WTI) was even lower near 0.03 during the same period. With a continuous shale gas production increase, Asian buyers are anticipating that this low volatility will continue into the future.
However, Asian buyers have not forgotten that an oil-linkage delivered lower prices than a HH linked formula in the past. The graph below (Figure 4) shows the difference between (1) an LNG price derived from a recent representative HH linked LNG contract formula\(^1\) applied to historical HH prices (2004 to 2012) and (2) an historical Asian LNG price (Japanese monthly average DES LNG price). It was only from late 2010 that calculated HH linked LNG prices were consistently lower than the actual Asian LNG price which consists of predominantly oil linked long-term contract prices. Obviously, the shale gas revolution which damped HH prices had reversed the advantage of oil linked prices to HH linked prices, from buyers’ perspective. Asian buyers do remember these historical trends.

\(^{1}\) Henry Hub formula used in this analysis was “LNG price = Henry Hub * 115% + $3/MBtu + $3/MMBtu (as estimated shipping cost to Asian market from US Gulf of Mexico).”
KEY STATEMENT 2: Increasing new supply sources but still limited share in the growing Asian LNG market

LNG exports from North America to the overall Asian market, even if all sold using gas-on-gas hub pricing, will not be sufficient to fundamentally impact the oil price linkage in Asia Pacific. The 15 to 25 MMt/y of LNG exports that we project from North America will only represent 6% to 10% of the total Asian demand of 257 MMt/y in 2020. Even adding East Africa's export potential to North America's exports only increases the share marginally. It is likely East African LNG contracts will be based more on traditional oil price indexation as there is no downstream gas market in the export location. Most of the new supply contribution will come from Australia, representing about 21% of the total Asian demand in 2020. Australia is a very expensive place to develop LNG and upstream infrastructure, and where the current representative HH-linked formula would not support project economics.
However, we expect indirect impacts on oil linked pricing in Asia from US LNG projects – 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 emerging is a blending of oil-linkage and gas-on-gas market prices, such as 5 MMt/y of portfolio LNG contracted between BG and CNOOC. These unique deals ultimately will come down to negotiations between buyers and sellers, taking into account the availability of existing supplies and economics of new projects.

**KEY STATEMENT 3: Challenging cost structures for green field projects in Asia Pacific**

Very large capital investment is required to support new liquefaction infrastructure. Investors in this new infrastructure will need to secure attractive long-term commercial arrangements to underpin project returns and financing. The main challenge facing supply projects worldwide, in recent years, 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 costs, 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). In recent years, there have been numerous unsettling announcements of cost escalations and project development delays, mainly from Australia.

Pricing long-term SPAs, that anchor the development of an LNG export project, against current or projected HH prices would be difficult for expensive green field projects. Non-oil linkage 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. At the same time, supply project sponsors have been pushing to maintain oil-linked pricing to make projects economic.
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. Most LNG projects would not be able to take FID if selling against gas hub prices. From a structural perspective – i.e., given the regionally fragmented nature of natural gas markets – a substantial shift to long-term HH or NBP pricing in Asia is still many years away. However, since there will be more supply options, buyers will focus more on cost competitive projects that could agree to a lower oil price relationship, down to a certain level, such as would be set by East African project economics.

**KEY STATEMENT 4: More supply competition towards the end of this decade and beyond – Poten Asia Pacific Market Competition Index**

The advent of new LNG supply potential in North America and East Africa will increase supply competition but it does not mean that oil linkage will disappear in Asia – it is more about downward pressure on the relationship between LNG price and oil price. We believe that increasing competition among suppliers post-2020 is likely to drive Asian pricing down to a level set by East African LNG project economics. We consider East Africa will be more cost competitive than other green field Asia Pacific LNG supplies. East African projects will compete with each other for Asian market share – potentially lowering slopes and reordering the supply project development sequence – and higher cost projects will be replaced by more competitive ones.

The Poten Asia Pacific Market Competition Index (PAPMCI) shows that Asian markets will be more competitive for suppliers seeking contracts starting in the 2020 to 2025 period (the PAPMCI increases from “2” in 2020 to “5” in 2025). Although Asia will continue to need new long term LNG supplies, increasing numbers of projects will be ready to target the Asian market post 2020. LNG projects will seek to sell their output long term to Asia – typically 5 years prior to first production. Any new potential supply projects that don’t find anchor buyers will be delayed into following years.

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2 Poten has developed *Poten Asia Pacific Market Competition Index* by comparing Asian yearly incremental unmet long term demand to the supply from new projects seeking to take FID. A higher index shows more supply competition in Asia Pacific leading to lower slope to oil indexed prices, and a lower index vice versa.
KEY STATEMENT 5: Asian gas-on-gas market price indexation not near (China Case Study)

If the existing gas-on-gas markets, such as the US, the UK and Northwest European gas markets, were to provide a guideline, physical connectivity and market deregulation are necessary to create viable natural gas hubs. Hence, critical factors for Asia to develop an effective, liquid, transparent and trusted gas-on-gas marker price are as follows:

- An interconnected gas transmission pipeline system
- Deregulated markets, including in natural gas upstream, transportation and trading
- Transparent market with limited government intervention
- A large and efficient short term and futures market with many buyers and sellers competing for positions.

Other important factors that would enhance gas-on-gas market price development are:

- Growing domestic production
- Growing pipeline imports and exports
- Substantial storage capacity
- LNG trade (as in the case of UK and Northwest Europe)
- High liquidity.
Currently there is no gas market in Asia that would clearly qualify for competitive hub pricing development. Can China develop an Asian gas-on-gas market hub price in the future?

**Favourable Physical Fundamentals**

China has some fundamental factors similar to gas-on-gas markets in North America – growing domestic production (both conventional and unconventional), and pipeline and LNG imports. Although there are many questions about how easy it is to extract shale gas in China, the US Energy Information Agency (EIA) has estimated that China’s two main basins – Sichuan and Tarim – could hold 1,275 Tcf of risked recoverable resources, the largest in the world. Another factor lacking today in China is pipeline infrastructure. While Chinese pipeline network is growing it continues to be limited, particularly when compared to the mature US pipeline network. Overall, these physical characteristics establish the potential for China to develop a future Asian gas-on-gas market.

**Table 1: Natural Gas Production, Imports and Exports, and Consumption in 2011**

<table>
<thead>
<tr>
<th></th>
<th>US</th>
<th>UK</th>
<th>China</th>
<th>Japan</th>
<th>South Korea</th>
<th>India</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved reserve (Tcf)</td>
<td>300</td>
<td>7</td>
<td>108</td>
<td>Minimum</td>
<td>Minimum</td>
<td>44</td>
</tr>
<tr>
<td>Technically recoverable shale gas resources (Tcf)</td>
<td>862</td>
<td>20</td>
<td>1,275</td>
<td>-</td>
<td>-</td>
<td>63</td>
</tr>
<tr>
<td>Domestic production (Bcf/d)</td>
<td>63</td>
<td>4</td>
<td>10</td>
<td>Minimum</td>
<td>Minimum</td>
<td>4</td>
</tr>
<tr>
<td>Pipeline imports (Bcf/d)</td>
<td>9</td>
<td>3</td>
<td>1</td>
<td>-</td>
<td>-</td>
<td>3</td>
</tr>
<tr>
<td>Pipeline exports (Bcf/d)</td>
<td>-4</td>
<td>-2</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>LNG imports (Bcf/d)</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>10</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>LNG exports (include. re-export) (Bcf/d)</td>
<td>-0</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Domestic consumption (Bcf/d)</td>
<td>67</td>
<td>8</td>
<td>13</td>
<td>10</td>
<td>5</td>
<td>6</td>
</tr>
</tbody>
</table>

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 a 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 are leaving gas importers suffering losses or requiring subsidies.

1 Ex-plant gas price is regulated by the central government, City-gate price is regulated by each provincial government
2 Average price for Nov’12 and Dec’12 from China Customs
3 Regulated by the central government, varied by distance
4 Poten’s estimate

**Figure 8: Current Pricing Misalignments**
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 pilot reform, natural gas prices will be pegged to that of alternative energies (fuel oil used in factories and LPG in households), using a 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/m³ (about $10.82/MMBtu) in Guangdong, and with RMB 2.57/m³ (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. While the gas price reform process has started, to get far enough down the road to support the emergence of a gas hub seems a long distance away.

**Insights from US and UK gas hub developments**

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, sometimes involving privatization and the significant challenges involved in unbundling of vertically integrated gas organizations in the process.

<table>
<thead>
<tr>
<th>US</th>
<th>1970s</th>
<th>1980s</th>
<th>1990s</th>
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<tbody>
<tr>
<td>Deregulation process started in 1970s from unbundling</td>
<td></td>
<td></td>
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<tr>
<td>1970s – Natural Gas Policy Act put FERC in charge of intrastate and interstate natural gas production.</td>
<td>1980s – US eliminates take-or-pay clauses from gas supply agreements to create competition among natural gas suppliers.</td>
<td>1990s – Pipelines and other facilities, including LNG terminals, were transformed into capacity service providers through Open Access. NYMEX started Henry Hub trade.</td>
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<table>
<thead>
<tr>
<th>UK</th>
<th>1970s</th>
<th>1980s</th>
<th>1990s</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deregulation process started in 1980s with privatization</td>
<td>1980s – Liberalization began with the Natural Gas Act in 1986, which set the necessary regulatory framework. British Gas privatized in 1986.</td>
<td>1990s – British Gas 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. NBP started in 1996.</td>
<td></td>
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**Figure 9: It Took Over Thirty Years for US/UK Gas-on-Gas Markets to Develop**

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. The process in China will be no easier where the gas industry is dominated by the three government owned oil and gas companies: CNPC, Sinopec and CNOOC. It will be a major challenge to restructure these behemoths.
4. RESULTS

Increasing LNG exports from new supply regions, notably North America and East Africa, by end of this decade and beyond will only partially drive global price integration – there would be no fundamental change in the Asian LNG pricing mechanism landscape.

- **The increase in LNG exports from North America and East Africa will not cause Asian LNG prices to materially delink from oil indexation**

Most of the LNG produced from the US will be lifted on a HH-linked basis and a portion could be sold at oil price linkage for the destination markets. Canada could take a basket pricing approach that is currently not clear. Even if all North America LNG were to be gas-hub linked, it represents no more than 10% of the total Asian demand in 2020. This is not sufficient to make Asian LNG prices, existing and new, materially delink from oil indexation. It is likely that contracts with greenfield East Arica LNG projects will be more of the traditional oil price indexation as there is no downstream gas market in the export location, and their economics need to be supported by oil linked prices. Due to increasing supply competition in the market, however, the real issue for new supply projects will be cost competitiveness and an ability to provide a lower slope in oil price indexation to anchor Asian buyers.

- **New pricing mechanisms – anywhere between a traditional oil-linkage and a Henry Hub linkage – are emerging**

Many Asian buyers are trying to achieve hybrid pricing mechanism in their new long-term contracts. It is too early to tell how this will actually develop but buyers’ appetite is real. And, as buyers are seeking supply diversification (locational and pricing), some sellers, such as so-called global portfolio suppliers, are considering price diversification in case oil price goes down and HH price goes up. In a “stress test analysis”, when oil prices go down to $65/Bbl and HH goes up to $4.5/MMBtu, HH linked contract prices to Asian markets could be higher than oil price indexed ones.

- **A local Asian gas-on-gas market price will not develop as an alternative base for pricing LNG in Asia in the near to medium term future**

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.

5. SUMMARY/CONCLUSION

We are at a very interesting and exciting moment in time. Driven by the shale gas revolution in North America, we are seeing growing North American LNG volumes targeting Asia Pacific. Major gas resources found in East Africa will also be another supply option for LNG hungry Asian markets. 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, which is a country challenged by high cost and limited labour resource availability. The development of complex and expensive LNG supply projects in the Pacific Basin will require a higher price level than North American prices provide.
In this paper we projected supply competition emerging toward the end of this decade and beyond with more potential for non-oil linked priced LNG from North America. A “foreign” gas-on-gas market price impact on Asian LNG market will be indirect – there will be limited delinking from oil price indexation. Forty years of Asian LNG industry tradition will be resistant to dramatic change. It is more a question of exactly how the oil linkage is set rather than will there be an oil linkage or not. 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. And lastly, the emergence of a genuine Asian gas hub will take a long time.