Lantau Pique

In this edition

In this issue of Lantau Pique, we call out Asia's growing kinky gas supply curve club and explore ways to reconcile the differences between domestic versus international gas pricing.

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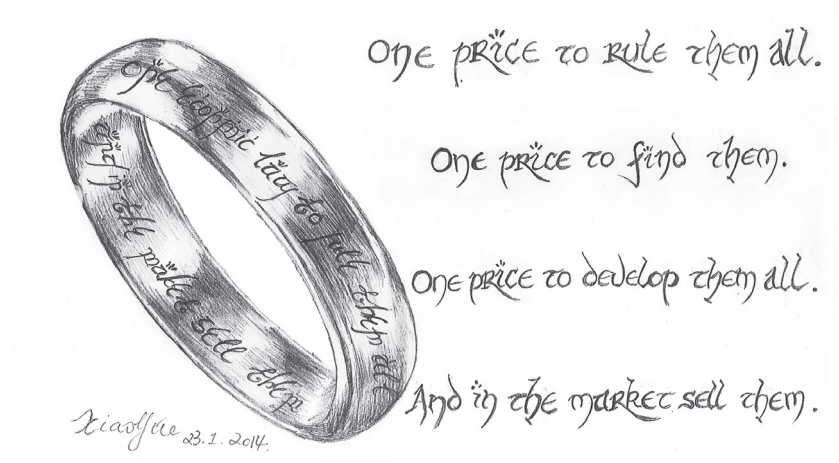
One Price to Rule Them All: Asia's Kinky Gas Supply Curve Club

Domestic gas pricing is at a crossroads throughout Asia. For many years, countries with local gas supplies, such as Thailand, Malaysia, Philippines, Indonesia and Vietnam, have been locally self-sufficient. Without a connection to global gas markets, they have enjoyed locally-determined natural gas prices. These locally-determined prices typically are materially lower than prices paid by Asian LNG importing countries such as Japan, Korea and Taiwan.

A combination of waning local production growth and rising local gas demand has led several previously self-sufficient countries, such as Thailand and Malaysia, to start importing LNG. For example, Thailand has been running its new LNG import terminal for more than two years and is planning to further expand it. Malaysia's Melaka LNG import terminal started up last year. Vietnam expects to commission its first terminal in 2016, although construction has not yet started[1]. Consequently, more of Asia is connecting up to the global gas market and becoming exposed to the vicissitudes of international fuel pricing dynamics.



One response to these sometimes unpleasant vicissitudes is to maintain separate pricing arrangements for domestic gas as compared to international gas – an approach that has obvious value management benefits, but can create a severely kinked gas supply curve in countries with as yet developed domestic gas resources.

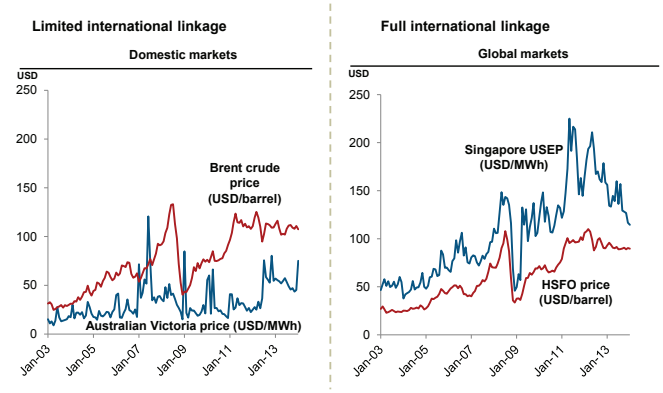
1 Some countries can export LNG from some locations and import (or plan to import) LNG into other locations, given the absence of the otherwise necessary thousands of kilometres of subsea pipeline. Malaysia, for example, exports LNG from Bintulu (Sarawak) and imports LNG at Melaka (Peninsular Malaysia). Indonesia faces similar challenges, with export facilities and opportunities in several locations, but a simultaneous need to import LNG into otherwise unconnected regions.

When Worlds Collide

When previously isolated gas markets connect to the international gas market, the economic 'law of one price' kicks in, and local and international pricing collide. The collision can be big. The left panel of Figure 1 depicts the eastern Australian NEM. Wholesale electricity prices in the NEM have been independent of global fuel prices because the majority of fuels used to generate electricity is locally supplied and (at least until new gas export infrastructure is commissioned in Queensland) does not have access to international fuel markets. The right panel, in contrast, depicts the Singapore NEMS, where electricity prices tell a very different story. Singapore has no local fuels, so electricity prices have always been strongly linked to international fuel markets.

Now, imagine trying to move a country from the left panel to the right panel. This is what must happen (to varying degrees) when a previously self-sufficient country or region joins up to the international gas market. Eventually gas users (in this case the power sector) face different risk profiles and cost levels.

Figure 1: Local vs Global: Different Prices and Risks



Source: Australian Victoria price is based on released electricity price from AEMO; Singapore USEP is based on electricity price from EMC website; Brent and HSFO price indexes are based on daily prices quoted in Platts.

The collision involves two elements: value management and economic efficiency. Value management is about who wins and loses when the cost of new gas differs from the cost of legacy gas. Economic efficiency is about sending the right price signals to those who make decisions about how much gas to develop, produce or use.

Some arrangements reconcile these two elements better than others. The best of these arrangements use contracts with defined volumes for legacy (historically developed or priced) gas and allow new gas to be priced at market. The worst fail to distinguish commercially between legacy and new gas volumes. An across-the-board price increase that applies to all gas molecules no matter where they come from clearly conforms to the economic law of one price, but it also causes the largest potentially disruptive shift of value between gas producers and gas users. The law of one price requires that *new* gas be priced at market (and preferably that gas users can trade their contracted gas volumes with each other to maximise efficient use of gas). The law of one price is equally well satisfied if legacy gas is sold under defined volume contracts at prices that were satisfactory to the contracting parties when they entered into those contracts.

A simple example may help:

- Option 1 involves allocating a legacy gas supply of 1000 mmscfd to gas users at a fixed legacy price of "A" and letting them buy additional gas at the imported LNG price of "C".
- Option 2 involves selling gas at some weighted average price "B" for as much gas as the customer wants.

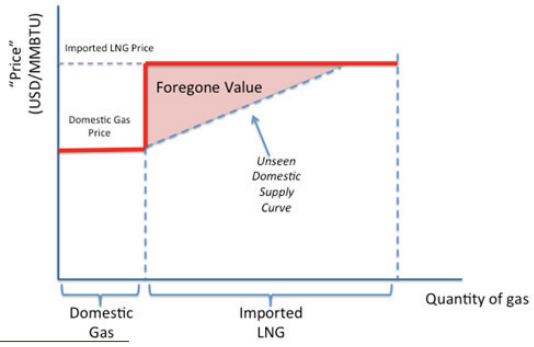
Of these two options, only Option 1 satisfies the law of one price. The latter option sends the wrong signal: both about the cost of incremental gas supply and about the value of incremental gas demand. Option 1 is less common in Asia, however (although Malaysia has recently adopted a version of it for its power sector). Instead, most countries implement some messy version of Option 2, hiding the real economics from everyone and making it more difficult to find a sensible pathway towards a more dynamic sector.[2]

Joining the Club

A country joins the kinky gas supply curve club when it prices new domestic gas supplies at one (lower) level, while importing LNG at another (higher) level. Policy makers or gas buyers may think they are managing value for end users by constraining the prices paid to develop new domestic gas resources. But the underlying situation is far more complex.

Often, we find that domestic gas is contracted at prices up to, but not beyond, some 'acceptable' domestic price. Figure 2 shows how a kink arises at the point where there is no more domestic gas available at this price. Consequently, the country imports LNG to fill the gap to meet demand. Without access to the imported LNG price, gas developers neither explore nor develop domestic resources to the extent that they might otherwise. The result is foregone value.

Figure 2: Left in the ground, an incomplete domestic supply curve



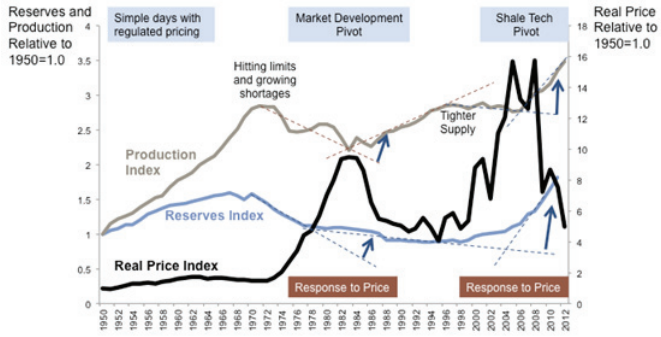
2 Even when countries appear to adopt option 1 in their new pricing regimes, the underlying structures are actually more like option 2 if one investigates the pricing regimes in detail. For example, in the latest natural gas pricing reform, China has separated pricing for legacy gas (defined as 2012 consumption volume of 112 billion cubic meters) and incremental gas (for both incremental domestic supply and pipeline imports). However, the pricing signal is still mixed as the newly set prices for new gas are still not enough to compensate for pipeline gas and LNG imports, and the government increases the prices for legacy gas so as to compensate for the financial loss from imports for CNPC. The Chinese government understandably seeks to share the pain of gas price hikes across stakeholders, but the way it has chosen to do this creates a kinked supply curve.

The total value foregone depends on the actual supply curve, which is never known with certainty. Experience suggests, however, that it can be material. In 1994, Thailand's then Mineral Fuels Division estimated Thailand's recoverable gas reserves (proven, probable, and possible) at 15 Tcf. Since then 15 Tcf has been produced, and recoverable reserves now stand at 22.2 Tcf! To the unaided eye, reserves estimation undoubtedly smacks of dark magic!

But the magic is not difficult to understand. It costs money to find and prove the commercial viability of reserves. The money spent depends on the return expected. Gas markets promote reserve development by making clear that gas can be sold at the market price. When supply tightens, the market price rises, and exploration picks up.

The US shale gas story and the associated increase in estimated US gas reserves is a good example of how reserve estimates respond to market activity. Figure 3 summarises the history of US gas pricing, production, and reserves dating back to the 1950s, when the US regulated natural gas prices in the same way seen throughout Asia today. For decades, simple regulation worked fine, with rising production and increasing available reserves. But in the late 1960s, the trend reversed. Reserves peaked, but production continued to grow. In the 1970s, regional gas shortages emerged. US regulators adjusted pricing, but often wound up moving shortages around rather than curing them, as dynamically balancing supply and demand across multiple gas-using regions is difficult.

Figure 3: US Gas Prices[3]



Eventually the US deregulated gas pricing.[4] Prices increased sharply, arresting the rapidly falling estimates of reserves, as new exploration activity soared. Production growth resumed, and prices fell back downward. A similar process played out again in the early 2000s with an even more dramatic result. The combination of attractive prices and technological advances launched the shale gas revolution. Reserves now stand higher than they were known to be at their early 1970s era peak.

Asian experience today is far more similar to the US experience in the 1970s than to US experience in the 1980s or more recently. Surely dynamic Asia is not forty years behind?

Seeking More, Getting Less

Figure 4 zooms in on the kinky gas supply curve problem. Historical contracts are shown as steps, reflecting the different contract prices paid to legacy developed gas resources. Now, suppose that a central gas buyer seeks to negotiate a contract with a new source of domestic gas supply (as PTT does in Thailand). Suppose further that through diligent negotiations, the buyer secures (or regulator finally approves) a contract from a new or enhanced existing field at a price lower than the imported LNG price. The value "X" shown in Figure 4 is the amount "saved" for consumers, who might otherwise have had to pay a higher price to cover additional imported LNG.

Figure 4: Thailand's Situation

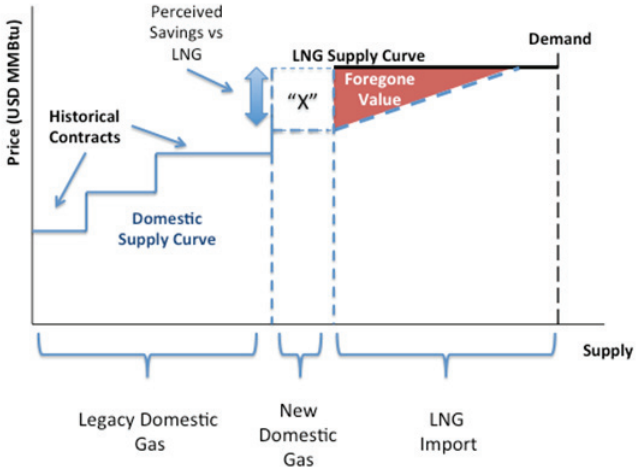


Figure 4 reflects a common scenario in Asia. Instead of moving directly to market-based pricing (consistent with the economic law of one price), effort is expended to negotiate new domestic gas contracts on an individual basis, attempting to get the lowest possible price. Or domestic pricing is otherwise constrained by unwillingness or inability to price new domestic gas separately from existing domestic gas – increasing the otherwise unnecessary disruption that results when prices for all gas (not just new gas) must increase to support more domestic production. Either way, whether through slow or cumbersome contract-by-contract negotiations or through awkward domestic gas pricing mechanisms, the foregone value triangle remains – as shown in Figure 4.

The reality of such domestic gas pricing policies and mechanisms is that the "savings" seemingly achieved for the consumer may not be much savings at all – the country winds up paying more

3 US EIA Reserves Index is based on U.S. Dry Natural Gas Proved Reserves (Billion Cubic Feet) (series: RNGR11NUS_1). Production index is based on U.S. Natural Gas Gross Withdrawals (MMcf) (series: N9010US2). Price index is based on U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet) Nominal (series: N9190US3) adjusted using the US GDP Implicit Price Deflator (series: GDPDEF, BEA Account Code: A191RD3). Index calibrated such that 1950 equals 1.0. Price index reported shown on right-hand Y-axis to highlight reserves and production response (left-hand Y-axis).

4 The US passed the Natural Gas Policy Act of 1978, which started the process of deregulating wellhead prices. By the 1990s, the US had fully liberalised its gas market.

for imported gas, develops a less robust domestic gas supply industry with higher long-term risk of gas shortages, and loses the potential benefits of further domestic investment, tax revenues, and associated industry development. For members of the kinky gas supply curve club, the extra goodness extracted in a single contract by the very best regulated gas buyer can easily be lost to the extra badness that results because the buyer misses other domestic gas resource development opportunities, therefore having to buy too much LNG at a higher price.

What might be done differently?

Introduce a Market?

One option is to make do with existing arrangements while working more intensively to develop a roadmap and transition to a gas trading market.

In Thailand, for example, the Energy Regulatory Commission has early-stage plans to introduce third-party access to the Thailand gas pipeline transmission system. Currently, the Singapore government is actively studying the feasibility of creating a secondary gas market and seeks to become Asia's regional gas trading hub. Indonesia has long had a mix of pipelines with and without open access, and since late 2013 has become entirely open access. However, negotiations over access have often been an uphill struggle. In addition, the Indonesian upstream regulator still approves each upstream gas price, so the kink in the supply curve remains. In China, the government has also been studying the feasibility of third-party gas pipeline access since 2011. China is also in an early stage of trying to create a gas hub price in Shanghai based mostly on LNG imports, but the volumes of gas traded in the Shanghai Petroleum Exchange is reported to be negligible most of the time.

These positive aspirations aside, domestic gas pricing is currently in such a state in so much of Asia that it hardly seems practical to simply wait for a perfect market to emerge, like Athena, full grown from the head of Zeus. The challenge is to ensure that talking about the problems drives meaningful efforts to solve them. Good things take time, which is why it is sensible to start reform processes even when things seem to be working. The heavy lifting that established the US gas market was done in the 1980s and early 1990s, taking over a decade to go from design to implementation to maturity. Once things break down, the mess can be even more difficult to fix.

Market reform is not all unicorns and rainbows, however. Great challenges await those who aspire to develop energy markets. The easier challenge, ironically, is the one that motivates most reforms: the desire to improve economic efficiency. The more difficult challenge involves figuring out how best to mitigate the potentially large disruptions to value that occur when transitioning from the pre-market to post-market world. These are not necessarily always price increases. For example, when the UK adopted a market-based approach in the early 1990s, the dash for gas almost immediately followed – a reflection of unique circumstances at the time. New gas prices fell below the cost still being paid by British Gas for its contractual commitments to existing gas suppliers. Whenever legacy commitments are more expensive than new opportunities, the result is stranded costs, for which someone ultimately pays. British Gas eventually renegotiated many of its legacy contracts, pushing some stranded cost risk upstream to the legacy gas suppliers. These changes involved a reduction in gas prices, not an increase. But the disruptive effect is equally real.

In Asia, contracting for LNG is becoming more risky. Prices are high due to Japan's post-Fukushima increased demand for LNG and the higher-than-expected project costs for upstream development and the associated liquefaction plants. But future demand is very uncertain – Japan is still sorting out its post-Fukushima fuel mix. The lack of flexible and dynamic gas market arrangements in Asia increases risk to investors in both long-term LNG supplies and in the development of new domestic gas resources. It also raises costs to gas users who may find that gas suppliers have locked in long-term take-or-pay contracts for LNG supplies at the top of the market. In such an environment, rapid moves to full market pricing may have many unexpected transition costs.

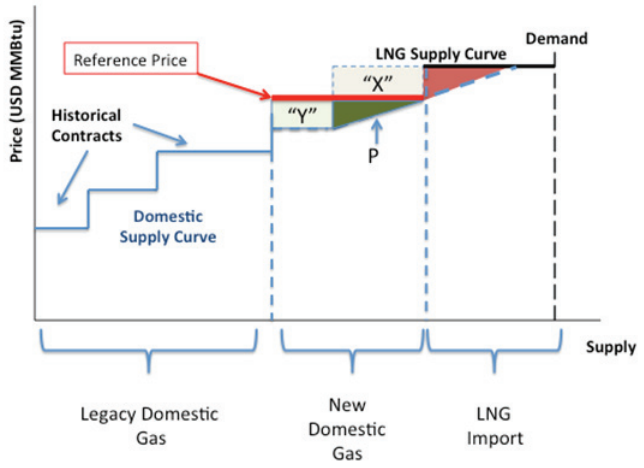
Consider Establishing a Reference Price

One approach that is much better than doing nothing – and that is perfectly compatible with bolder longer-term solutions – is to develop a reference price for domestic gas. The reference price should reflect the estimated market-clearing price, which is basically the imported LNG price. If the market-clearing price cannot be directly achieved, then the reference price can be linked formulaically to a basket of LNG value markers.

The reference price can be set at any level up to the price of imported LNG – the level determines the trade-off between minimising the need for transitional value management versus maximising domestic resource development. If the reference price is set below the imported LNG price, then the reference price will not be perfectly aligned with the law of one price, but it can still be several steps more aligned than what is achieved currently in most Asian countries. And doing so can help recognise legitimate aspirations among populations to see a continuing benefit from "their" national resources.

Consider Figure 5. Area "Y" is the increase in cost paid by end users as a result of stopping the contract-by-contract negotiations process that would have yielded an additional cost-plus contract at some price lower than the reference price. Area "X", in contrast, is the savings to end users associated with gaining access to new domestic gas at a reference price below the LNG price. If area "X" is greater than area "Y", then not only is more domestic gas developed and brought to market, but the overall price of gas to end users is reduced (relative to a world in which more LNG would have been imported).

Figure 5: Finding a balanced reference price



The "red" triangle is the much-reduced area representing missed opportunities to develop even more domestic gas. The red triangle is not lost forever, as it may be possible to develop these resources in the future if the reference price increases or extraction costs decline.

The "green" triangle (labelled "P") is the additional benefit to domestic gas producers above their absolute minimum cost of resource development and extraction. In economic terms this is the rent (profit) they earn for being lower cost than the reference price. This profit is higher than they would have required in a perfect world of perfect domestic gas contracting, but it is unavoidable in the real world. It is a benefit to the domestic gas industry that comes at no cost to end users, who would otherwise have to pay the cost of imported LNG. And it is not entirely lost to the country—much of this rent will return to the government in the form of increased royalties, taxes and sales revenues.

If the hoped-for domestic supply response to the reference price does not happen, then area "X" will be smaller than area "Y" and end user prices may increase somewhat. Even if this occurs, an appropriately designed tax or royalty system could claw back much of this rent, for the benefit of the wider economy. But if the hoped-for supply response is large enough, then end users can see savings, relative to the LNG alternative, due to area "X" being larger than area "Y".

The ideal point depends on the objective. The lowest end user prices are achieved when the difference between "X" and "Y" is greatest. The greatest national benefit for a given end user tariff level occurs when "X" and "Y" perfectly offset each other. The first step is to define the objective so as to reduce the otherwise arbitrary nature of the reference price concept. The remaining steps include comprehensively assessing available supply and demand information; conducting appropriate industry consultation, developing and analysing scenarios; and possibly developing innovative mechanisms to elicit insight into the likely quantum of new supply response.

Summary

Gas pricing in Asia is a righteous mess. Prices in most countries do not send the right signals to any stakeholder. Many risks cannot be easily managed. The gap between regulated and hypothetical market-based prices is large and daunting. And gas is almost certainly being left in the ground that could increase value for many countries. Take Thailand, for example: undeveloped gas resources are known to exist; the gas resource sector has multiple interested parties; the process of developing and contracting resources has been cumbersome and slow; and Thailand is increasingly exposed to the higher cost of imported LNG. Similar initiatives would also make sense in many other gas-rich Asian countries, such as China, Indonesia, and Malaysia.

By simplifying pricing to new domestic gas resources and focussing on the endgame – a more robust long-term transition to a gas market -- some gas producers might make more money (and pay higher taxes), but the additional gas brought to the market would displace much more expensive LNG.

If it can be found, the sweet spot where "X" is greatest relative to "Y" ensures that both consumers and producers benefit. But even a lesser supply response has the potential to produce significant net benefits to the country. Getting all the settings right would take some work. Developing a proper roadmap for industry development over time would be the sensible next step.

The result can be a win/win.

About the authors

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Mike has advised energy sector stakeholders on sensitive regulatory, commercial, and strategic matters for over 25 years. He is an expert in the rigorous analysis of energy sector decisions including: how or whether to regulate; how and when to rely on market forces; and what value to place on opportunities and risks. Prior to co-founding The Lantau Group in 2010, he headed the Asia Pacific Energy & Environment practice of a global consulting firm. Mike has an MPP from Harvard Kennedy School and a BA in economics from Carleton College.

Neil Semple

Neil brings over ten years' experience as an advisor to gas and power stakeholders. For gas companies he has prepared gas monetization plans and strategies, assessed competition between piped gas and LNG, developed LNG terminal regasification tariff mechanisms, and analysed a wide variety of small and large gas-supply opportunities and applications, including transport. For power companies, he has advised on LNG vs piped gas and other fuel sources, and on the economics of various forms of electricity generation in merchant and non-merchant markets. Neil has an MA in economics from the University of Aberdeen.

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Liutong is an expert in the oil and gas sectors and how these sectors affect the economics of power generation throughout Asia. He has extensive experience analyzing the dynamics of international fuel-linked energy markets such as Singapore and the Philippines, as well as the many regulated and transitional markets elsewhere in Asia. He joined TLG from FACTS Global Energy (FGE) in Singapore, where for over three years he advised international oil companies, national oil companies, traders, institutional financial institutions, private investors and government clients on issues such as gas/LNG sourcing strategies, investment due diligence, and energy demand and price forecasting. Liutong holds a Bachelor of Chemical Engineering with first class honours from the National University of Singapore (NUS). He is fluent in English and Mandarin.

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