LNG’s Uncertain Future: Will Spot and Short-Term Pricing and Contracting Become the Norm?

January – 2020

The Abdullah Bin Hamad Al-Attiyah International Foundation for Energy & Sustainable Development
LNG’s Uncertain Future: Will Spot and Short-Term Pricing and Contracting Become the Norm?

LNG prices are currently low and supply is ample. As sellers search for markets, and spot prices fall below long-term contract prices, oil-linked pricing formulae come under strain.

Will the oil link be replaced entirely by traded gas-on-gas markers such as JKM? Will short-term and spot cargoes become the norm, as the LNG market evolves to resemble the oil market? Or are long-term, oil-linked contracts still irreplaceable?
EXECUTIVE SUMMARY

- LNG contracting has changed over the past decade, with more liquidity and flexibility; a greater variety of suppliers, traders and buyers; a greater variety of pricing methods; and more use of spot and short-term trade.

- The last year or so of oversupply has led to spot prices in Europe and east Asia falling well below oil-linked prices, and pushed traditional long-term contracts towards review and renegotiation.

- Cost-based, Henry Hub-linked contracts from the US have proved problematic due to the exposure when global LNG prices fall, and the lack of linkage to end-user markets in Asia. But oil-linked contracts are also out of sync with LNG market dynamics, with oil prices remaining relatively robust.

- Nevertheless, the divergence between Japan Korea Marker (JKM) and oil-indexed Japan Crude Cocktail does not ensure that Asian LNG importers will shift to spot pricing, as JKM is not yet a fully traded price.

- From 2020 onwards, the LNG market will see further growth in hybrid pricing, with a mix of indexations in short as well as long-term contracts.

- A single LNG pricing hub will not emerge, and arbitrage will remain between the main pricing points, although there should be a degree of price convergence.

IMPLICATIONS FOR LEADING OIL AND GAS PRODUCERS

- Suppliers will need to allow renegotiation and review of contract terms with buyers to ensure long-term offtake. Renegotiation, with increased offtake, may be preferable to the uncertainties of the formal price review process.

- Liquidity plays an integral role in determining a benchmark for LNG pricing, and currently is still too low for JKM (and even more other markers) to be considered a true hub price.

- Asian markets should further develop JKM to become a fully traded price to meet demand fluctuations and hedge risks.

- Oil-linked pricing will probably remain the majority of global sales, particularly in Asia, but the diverging fundamentals of oil and LNG make it increasingly problematic. The emergence of a range of gas hub prices, including China and perhaps India alongside JKM, may bring lower prices but would help leading LNG exporters compete with coal and establish sustainable demand.
However, LNG pricing in Asian markets, mainly Japan, South Korea and Taiwan, remained tied to oil, such as the Japan Crude Cocktail (JCC), which closely follows Brent crude. In 2011, following the oil price spikes and the Fukushima nuclear accident leading to the closure of all Japanese nuclear power stations, demand saw a sharp increase, pushing Asian buyers towards JKM (Japan-Korea Marker) spot pricing and short-term LNG cargoes. Consequently, price differentials expanded with JKM far above European National Balancing Point (NBP) and US Henry Hub (HH). JCC was preferred due to greater price stability.

After the fall in oil prices to $45-50 per barrel in 2014-16, Asian LNG prices dropped from $15-18/MMBtu to less than $5/MMBtu in Q2 2016, leading to narrowed price differentials. At times, JKM (East Asian spot) prices fell to the operating costs of US exporters, which would have compelled shut-ins had they remained below that level for an extended period.

It had long been forecast that global gas prices would converge as LNG trade expanded and became more liquid. Some commentators expected it to move closer to the oil market, with few long-term contracts, and prices determined in competition with other gas or energy sources, rather than by indexation to oil.

This has happened to an extent, but the route has been lengthy and marked by periods of sharp change as well as retreat.

The development has been driven by the interaction of three factors:

- Periods of oversupply and low prices
- Regulatory action in favour of liberalised markets (EU and Japan) and greater buyer power
- The emergence of new buyers, sellers and intermediaries, and hence a more varied and liquid market

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CONTRACTS HAVE CHANGED FASTER WHEN OVERSUPPLY HAS PUT PRESSURE ON SELLERS

This pattern changed again with China’s unexpectedly high LNG demand in 2017-18 as it introduced environmental policies to shift from coal to gas, raising the price above $10/MMBtu, while European prices increased to $7.5/MMBtu in summer 2018, signalling a tight LNG market (as shown in Figure 1).

However, with new plants ramping up in Australia, Russia, US and Qatar along with lower Asian LNG demand due to warmer weather, a slowdown in Chinese coal switching, and Japan’s nuclear power plants restarts, LNG prices reached a three-year low, at an average spot price of $4.4/MMBtu and NBP price of $3.4/MMBtu in 2019 (FIGURE 2).

The EU has, since the early 2000s, been trying to enforce a more competitive and flexible gas market, reducing the power of big incumbent suppliers. In particular, it insisted on the removal of destination clauses, allowing re-sale of gas within the bloc.

East Asian buyers have traditionally preferred oil-linked pricing because of their lack of alternative gas supplies, and their prioritisation of supply security over low pricing. Regulated utilities could pass on their procurement costs to customers. Meanwhile, LNG sellers also liked oil-linked pricing because it gave the certainty to underpin and finance long-term investments.

However, here too, changes in market structure have pushed for lower LNG prices and a weakening of the oil link. Two of the biggest Japanese buyers, TEPCO and Chubu Electric, formed a JV, JERA, in 2015 to give them greater negotiating power, and JERA signed a cooperation agreement with KOGAS (South Korea) and CNOOC (China) in 2017, and formed a JV with EDF in April 2019. In April 2016, Japan’s electricity market liberalisation went into force, which encouraged its utilities to reduce their fuel procurement costs.

MARKET LIBERALISATION HAS INCREASED PRESSURE ON PRICE COMPETITIVENESS

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Greater diversity in the LNG market has been driven by:

- New suppliers – particularly in the US, from shale resources
- New buyers, including emerging markets using floating storage and regasification units (FSRUs) to access relatively small, uncertain or time-sensitive markets.
- New intermediaries, particularly trading companies such as Vitol, Gunvor and Trafigura; but also resale of cargoes from traditional buyers who had become over-contracted; and ‘portfolio’ purchases by major oil and gas firms to guarantee offtake from their own liquefaction projects.

Several new LNG suppliers have emerged in recent years, particularly Arctic Russia and several new Australian projects on both east and west coasts, but also Papua New Guinea and Angola.

The impact of US shale gas, though, has been the most important, because the country’s LNG exports are on a large scale – and expected to grow much more; they are spread between numerous companies, mostly not traditional incumbent LNG producers; and they have adopted novel pricing schemes instead of seeking oil-linked pricing.

In 2012, Cheniere became the first US company to commit to exporting LNG (other than the small 1969 Kenai plant in Alaska), and in 2016, it began exports. It introduced a new pricing model, where off-takers committed to pay the Henry Hub price for feedstock, plus a factor (initially 15%) for fuel gas, plus a fixed liquefaction charge ($3 per MMBtu in the initial contracts). This introduced a link to Henry Hub, as well as major exposure for buyers who could face European hub or Asian oil-linked prices in their intended market. A wave of US LNG plants has followed.

New buyers have also emerged in great profusion, even if many are relatively small (FIGURE 3). These give greater opportunities for trade and route optimisation.
The oversupply witnessed since 2018 until today is expected to continue for a couple of years with Asian and European prices likely to remain depressed. This supply glut might lead certain suppliers to reduce or shut-in production and export lower volumes in order to meet market pressure. Inflexible Asian markets still relying on higher-priced oil-linked contracts would not be able to step up imports much as LNG would still be uncompetitive with cheap domestic coal. Unlike in 2019, European markets, now with almost full storage, would be unable to absorb the glut.

US Henry Hub prices fell below $2 per MMBtu in early 2020, JKM could fall below $3 per MMBtu at times during 2020, and European gas below $2 in 2020. This would put great stress on existing contractual relations, as such prices would be well below oil-linked levels and Henry Hub-based LNG prices.

However, after 2024, with a relative slowdown in FID on new plants and anticipated demand growth, mainly in Asia (India and others), the LNG market is expected to tighten again (FIGURE 4).

In contrast to a well-supplied LNG market, the oil market is tighter. This is because of the supply cuts orchestrated by the OPEC+ alliance, and the loss of supply from geopolitically-troubled countries, particularly Venezuela and Iran.

This results in a growing disconnect between average import prices into Japan and South Korea, still dominated by oil-linked contracts (2/3 of Asian LNG imports in 2018 were priced based on oil), and the JKM spot price (FIGURE 5). JKM was closely correlated to average import prices, although it preceded them by a few months during the 2014-15 oil price fall because of lags in contract terms. But in 2019, while average import prices remained relatively strong, JKM fell sharply. JKM also responds more sharply to seasonal changes, being stronger in winter.
These developments have led to the emergence of three different types of LNG pricing:

- Oil-linked, as with most traditional Asian contracts
- Cost-based, as with the Henry Hub-linked US contracts
- Gas-on-gas, as with NBP, TTF, JKM, etc.

Oil-linked pricing remains popular, but is adapting to meet market realities. Instead of the previous linkage at 15–17% of Brent (i.e. a Brent price of $60 per barrel equates to an LNG price of $9–10.2 per MMBtu), the factor has steadily been negotiated down to 11%, or $6.6 per MMBtu. If oil-linked prices are relatively weak, this weakens the argument that new liquefaction projects “need” oil-linked pricing to secure financing.

Some contracts have been signed linked to other commodities. For instance, Shell and Tokyo Gas signed a long-term contract of LNG indexed to coal prices. While the price movements of coal are not related to the gas market, coal is considered the main competitor of LNG in Asia, representing 60% of power generation as compared to LNG’s 12% in 2018. This could represent a possible approach for imports into India and other coal-dependent Asian countries, but LNG prices would have to be low or strongly supported by environmental policies to outcompete local coal.

Cost-based pricing is so far limited to US projects using the tolling model, to limit the liquefaction plant’s developer’s exposure to price movements. But again, market competitiveness has driven down the fixed element of the price from $3–3.5 per MMBtu to lower levels for recent projects such as Calcasieu LNG. Tellurian is using a different approach, allowing project partners to invest in equity while receiving low-cost LNG in return. Portfolio players can balance cost-based purchases against oil or gas linked sales, but this exposes them to significant risk when international LNG prices fall faster than Henry Hub.

Gas-on-gas can follow one of two approaches. For LNG delivered into a liquid market such as the US or Europe, the price has to reflect the local benchmark (Henry Hub, NBP, TTF, etc.) plus any location differential. For east Asia, there have been attempts to develop a specific LNG benchmark. Platts’ JKM assessment was launched in 2009 as a measure of the spot price in east Asia\textsuperscript{xvii}. Trading volumes increased significantly in 2018 with JKM being used for more short and mid-term deals. Platts has a Middle East marker (at Egypt’s Ain Soukhne port), began offering an assessment of US Gulf Coast export prices in June 2016, and has now started an assessment at Singapore, an important trading point and importer of both pipeline gas and LNG.

However, the Singapore Exchange’s attempt to launch a traded LNG index was abandoned after four years in July 2019, due to inadequate participation\textsuperscript{xix}.

North-east China has been raised as a further possible hub, given that it is a growing LNG importer and receives pipeline gas from Russia, central Asia and domestic supplies. China launched a gas exchange in Shanghai in 2015, which has attracted little interest, and another at Chongqing (inland in south China, near production from Sichuan)
in 2018\textsuperscript{xxv}. In December 2019, it formed a national pipeline company, which also controls some underground storage and import terminals, which could give more access to independent gas companies\textsuperscript{xxvi}. But the continuation of price regulation, difficulties of re-export, and the risk of dominance by government or incumbent companies makes it difficult for a Chinese marker to have an international reach.

Even though JKM is receiving increasing attention, it is not to be confused with an Asian LNG price, but rather a spot price\textsuperscript{xxvii}. Its churn rate (the ratio of trades to the total market size) remains very low, although it has grown rapidly over the past three years, (FIGURE 5) and on many days, the reported price is determined by simple judgement rather than actual trades\textsuperscript{xxviii}.

Meanwhile, in a deal for supply to Cheniere, producer Apache is using a price linked to JKM\textsuperscript{xxviii}. Sales by Tellurian to Vitol and Total have also used JKM. Such arrangements signal two things: (1) US companies’ interest in exposure to global and particularly Asian markets and (2) JKM as a potential reliable LNG pricing benchmark for Asia. But Shell has signed with another US producer, NextDecade, for traditional Brent-indexed sales.

The question has often been raised, whether a single or a few linked dominant LNG/gas pricing benchmarks or hubs will emerge, as with Brent, WTI and Dubai-Oman for crude oil, which generally move closely together and have a quite predictable relationship.

This is unlikely for LNG, for a number of reasons:

- Compared to oil, the liquidity of LNG remains much lower, significant contractual and infrastructural rigidities remain, and transport and storage costs are a much larger fraction of the end-user cost.
- Despite the rise of trading companies and portfolio players, the LNG market is still highly un-optimised.
- None of the main Asian LNG markets – Japan, China, South Korea, Taiwan or India – are connected to the others by pipeline, unlike European countries. Indeed, only China imports gas by pipeline at all, and only China and India have significant domestic gas production.
- Two of the four main export players, Russia (in pipeline and increasingly LNG) and Qatar, have a much larger market share than any OPEC state for oil, and play strategically (the other two, the US and

Henceforth, a total move from oil-indexation in Asia is unlikely in the medium term, given that JKM is not yet a fully traded price as compared to NBP, which was already a liquid trading hub when Europe shifted from oil-indexation to an energy equivalent-basis.
Australia, are market-based with a diverse group of exporting companies).

- Restrictive trade measures, such as China’s tariffs on US LNG, and possible European measures to limit the carbon footprint of imported gas, would restrict certain suppliers from accessing key markets.

- And in end-user markets, while oil’s users are quite homogenous, LNG competes against different fuels: pipeline gas and coal in Europe and China, coal in India, only LNG in Japan-South Korea-Taiwan.

For these reasons, the linkage of the main gas hubs will probably become closer, but there will always be significant arbitrage between them, reflecting market power, different economic conditions, and infrastructure bottlenecks. In fact, buyers will likely take advantage of the weakness of an oversupplied market and use different indexations of hub (HH, NBP/TTF), spot (JKM, Argus and ICIS) and JCC prices as a risk management mechanism.

As FIGURE 6 shows, at current Brent futures prices and an 11% slope, oil-linked futures would again be below JKM by the winter of 2021. If this holds, the incentive for buyers to move to gas-on-gas pricing in Asia instead of oil-linked prices would be greatly weakened. JKM appears to be capped by full-cost US LNG prices (i.e. including the usual capacity charge of $3 per MMBtu, plus fuel gas, feedstock and shipping). UK NBP and Netherlands TTF remain significantly below JKM, but this appears mostly to represent cheaper shipping from the US. In the first half of 2020, European and JKM prices might test the shut-in level of US LNG exports, but after that, futures imply that American exports would at least be covering operating and transport costs.

![Figure 6 LNG Futures Prices](image)

**FIGURE 6 LNG FUTURES PRICES**

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**NOT JUST PRICE, BUT OTHER CONTRACTUAL TERMS ARE CHANGING**

It is not only LNG pricing that is in transition, but also LNG contracting relating to price reviews and term. Contractual price reviews emerged in Europe in the mid-1980s, did not feature in Asia until the 1990s, but have now become standard. Contract terms cover (1) conditions for a price review, (2) price review process and (3) price review methodology.

Under conditions for price review (1), price reopeners set temporal triggers to allow price revision, which were at intervals of 5-10 years in the 1990s and narrowed to 4-5 years recently. However, excepting the occurrence of certain circumstances, these price reviews usually do not specify the possibility of price revision outside the regular review periods, forcing parties to wait and constraining their efforts towards price flexibility.

For the price review process (2), negotiations of price reviews constitute the first step and come in the form of good faith discussions in the Asian context. However, their contractual
NOT JUST PRICE, BUT OTHER CONTRACTUAL TERMS ARE CHANGING

basis is rather vague, since they often do not specify a negotiation period, or in the case of failed negotiations, a recourse. This results in a long process with uncertain outcomes, discouraging price reopeners. In newer contracts, price clauses have become more detailed, setting a time limit for negotiations and providing one to three options in case the parties did not reach an agreement. One of the most adopted LNG contracts in Asia now provides parties at a disagreement the possibility to forward their dispute to an external dispute settlement, either arbitration or expert determination, rather than contract termination or remaining in full force.

- While arbitration is the preferred method to settle disputes in Europe, Asian contracts usually only require parties to "meet and discuss" the price of the contract. This is increasingly changing as new players are emerging and LNG projects are expanding, which pushes price review clauses to include recourse to arbitration to mitigate against protracted discussions.

- While expert determination has never been a better alternative to arbitration in Europe, Asian contracts seem to prefer their price review disputes to be resolved exclusively by an expert. Other contracts provide expert determination as an option.

As for price review methodology, most Asian contracts provide little guidance and limited instructions for price reviews, increasing the risk of unpleasant outcomes. Although a lack in instructions should not lead to major problems as long as the decision of the price review falls on the parties, in the case where good faith discussion does not reach an agreement, problems are likely to arise.

TABLE 1 RECENT LONG-TERM CONTRACTS VS PORTFOLIO PLAYERS GLOBALLY

<table>
<thead>
<tr>
<th>Supply Source</th>
<th>Seller</th>
<th>Buyer</th>
<th>Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>LNG Canada</td>
<td>DGI (Mitsubishi)</td>
<td>JERA</td>
<td>15</td>
</tr>
<tr>
<td>Portfolio</td>
<td>Shell</td>
<td>Tokyo Gas</td>
<td>10</td>
</tr>
<tr>
<td>PNG LNG</td>
<td>PNG LNG</td>
<td>Sinopec</td>
<td>4</td>
</tr>
<tr>
<td>Portfolio</td>
<td>Total</td>
<td>Guanghui Energy</td>
<td>10</td>
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<tr>
<td></td>
<td>Woodside</td>
<td>ENN</td>
<td>10</td>
</tr>
<tr>
<td>Arctic LNG</td>
<td>Novatek</td>
<td>Repsol</td>
<td>15</td>
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<tr>
<td></td>
<td></td>
<td>Vitol</td>
<td>15</td>
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<tr>
<td>CommonWealth LNG</td>
<td>CommonWealth LNG</td>
<td>Gunvor</td>
<td>15</td>
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<tr>
<td>Driftwood</td>
<td>Tellurian</td>
<td>Total</td>
<td>15</td>
</tr>
<tr>
<td>Rio Grande</td>
<td>NextDecade</td>
<td>Shell</td>
<td>20</td>
</tr>
<tr>
<td>Mozambique LNG1</td>
<td>Mozambique LNG1</td>
<td>JERA/CPC</td>
<td>17</td>
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<tr>
<td></td>
<td></td>
<td>Tokyo Gas/Centrica</td>
<td>20</td>
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<tr>
<td></td>
<td></td>
<td>Tohoko Electric</td>
<td>15</td>
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<td>CNOOC</td>
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<td>Port Arthur</td>
<td>Sempra</td>
<td>Saudi Aramco</td>
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</tr>
<tr>
<td>Plaquemines</td>
<td>Venture Global LNG</td>
<td>PGNIG</td>
<td>20</td>
</tr>
</tbody>
</table>

CONTRACT LENGTHS AND SIZES ARE DROPPING

It should be noted that these initial contractual changes were addressing merely price flexibility, while other issues related to destination, volume and indexation flexibility, among others, were left out. Due to the plurality of risks arising from long-term LNG contracts, global LNG procurement is also witnessing a shift toward shorter contracts with more flexible commercial terms.
This is especially seen with the emergence of portfolio players as intermediaries between buyers and sellers, with the capability to meet the needs of both end-buyers, looking for greater flexibility, and project developers, who need long-term assurance of offtake in case finance increases (TABLE 1). These portfolio players include supermajors such as Shell and Total, as well as trading companies like Vitol and Trafigura, and new entrants who may not use the LNG themselves, such as Saudi Aramco. Such companies are still willing to sign long-term contracts of up to 20 years. Flexibility on price reviews and destination is essential for such long-term deals given the uncertainty of market developments.

As the gas market became oversupplied and prices crashed, Asian buyers such as Japan’s JERA and Tokyo Gas have sought to reduce their LNG volumes received under contracts and demand greater flexibility in terms. The fall in gas prices made the disparity between oil-indexed contract prices and JKM spot prices more visible, pushing buyers to consider contract renegotiation, which might not prove successful according to some analysts. Yet, JERA mentioned that despite the risks, oil-linked contracts are still meaningful as they provide “stable procurement for buyers,” ensure demand needed by project developers, provide visibility on forward pricing and secure supply. For this reason, oil-linked long-term contracts continue to make up the majority of Asian LNG contracts, while the spot market along with short-term contracts represent 32% of global LNG trading, according to the International Group of LNG Importers.

The share of spot and short-term trading has only recently begun to increase (FIGURE 7). During 2011-2016, it hovered around 25%, but rose to 30% in 2018. The growing oversupply of LNG, the low price of spot compared to oil-linked LNG, the increase in more flexible US LNG output, and the growing prevalence of portfolio players, are all likely to drive a growing share of short-term deals, while they still remain a minority of the total market.
The future of LNG contracting will be heterogeneous, consisting of an amalgam of short as well as long-term contracts using diverse indexations, and an increasing presence of portfolio player projects and equity holders. The latter are expected to hold more volumes than consumers, with a 31% growth in shares in 2025 from 24% in 2019.

In addition to new liquefaction projects, old long-term contracts are expiring soon, which are likely to be renewed as shorter deals with lower volume and better terms of procurement.

The period to 2024 will be key, if the expected oversupply continues during this period. Asian oil-linked contracts are likely to move to increasingly low linkages, and pressure may emerge for a greater share of indexation to JKM or other gas-on-gas markers.

Nevertheless, the shift to gas hub pricing and more spot/short-term trading is likely to advance only incrementally, and may halt entirely if the LNG market tightens around 2024 as anticipated.

Low prices may be painful for LNG exporters, but they may also be necessary for gas to take market share from coal in Asia. The market would ultimately benefit from a range of tradable gas hubs, including one in China and even one in India, to allow sustainable and economically rational price formation.
APPENDIX

i. https://www.ft.com/content/25f09f44-11f4-11ea-a225-db2f231cfeae


ix. https://www.jera.co.jp/english/information/20170323_325


xii. Qamar Energy research


xv. Qamar Energy

xvi. Center for Strategic and International Studies


xx. https://it.reuters.com/article/idUKL4N1OT29Z


xxvi. Qamar Energy analysis based on data from CME Group, cmegroup.com


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Currently the Foundation has over fifteen corporate members from Qatar’s energy, insurance and banking industries as well as several partnership agreements with business and academia.
Our partners collaborate with us on various projects and research within the themes of energy and sustainable development.