Gaffney Cline

Market Advice and Estimates of Contemporary LNG Contract Prices

Prepared for

Australian Competition & Consumer Commission

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Gaffney Cline

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Basis of Opinion

This document reflects GaffneyCline's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by the Australian Competition & Consumer Commission (ACCC) and/or obtained from other sources (e.g., public domain), the scope of engagement, and the period over which the evaluation was undertaken.

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In performing this study, GaffneyCline is not aware that any conflict of interest has existed. As an independent consultancy, GaffneyCline is providing impartial technical, commercial, and strategic advice within the energy sector. GaffneyCline's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GaffneyCline has maintained, and continues to maintain, a strict independent consultant-client relationship with the Australian Competition & Consumer Commission. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or are related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

This report relates specifically and solely to the subject matter as defined in the scope of work (SOW), as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

Executive Summary

This report sets out the methodology proposed to estimate medium term LNG prices based on an oil index to enable a series of 6-monthly reports to be produced to supplement ACCC's existing LNG netback series. As informed by the ACCC scope of work, this will be focused on publishing oil-linked longer-term forward LNG netback prices extending to 5 years, calculated by reference to an oil slope. The ACCC is to seek consultation on this methodology, prior to final adoption.

The LNG industry has emerged and increased in scale over the last 60 years and continues to evolve. There continues to be a growing demand for LNG around the world, together with an increasing number of market participants including sellers, buyers, intermediaries and marine service providers. Furthermore, the industry is navigating wider considerations related to the global economic recovery post COVID-19, geopolitics, and increasingly the global move to decarbonisation and Net Zero.

The focus of this report is on the oil-indexed equivalent price of LNG in world markets going out 5 years, netted back to Asia (and from there to Eastern Australia using ACCC methodology). However, these current volatile factors give rise to additional challenges in identifying true underlying market conditions, versus temporary factors linked to wider concerns, especially energy security for the major markets of Western Europe.Market conditions in the first quarter of 2022 have been very substantially impacted by the Russia-Ukraine conflict and the major ramifications this is having on global supplies of natural gas. At the time of writing, European and Asian natural gas wholesale prices are at record high levels which most governments and industry players view as unsustainable. These high prices are giving rise to a range of temporary policy initiatives such as fuel subsidies, and government set caps on prices for some consumers which are having a substantial knock-on effect on gas pricing around the world.

As stated in the ACCC Netback Review Final Decision Paper dated September 2021[1], US Henry Hub prices have historically had limited impact on Asian LNG prices, especially in times of high demand which impact the short to medium term timeframe. This has been demonstrably the case over the last several months, with a major disconnection between the two. However, with US project construction times from FID to first LNG shortening to less than 30 months, and relatively short regulatory approval times (for Gulf Coast projects), this linkage may grow in the future (also as noted by ACCC). This linkage may also be influenced by political pressure from US and EU governments to increase US LNG volumes in response to Russian security of supply concerns, which may reinforce the US role as a "swing provider" of LNG to global markets

Notwithstanding this market volatility, the focus of this report is on a standardised methodology that will provide robust and methodologically consistent price estimates every 6 months for the 2022-2025 timeframe. The methodology set out in this report will aim to generate oil indexation parameters that gas buyers in Eastern Australia can use as a guide to market conditions. The methodology proposed in this draft report focuses on the following features:

1. An analysis of recent transactions in the LNG market, assimilated from a combination of public domain sources, paid subscriptions to accepted LNG industry data sources, and market intelligence gathered from GaffneyCline's wider exposure to the LNG industry. GaffneyCline carries out commercial and economic analysis for a range of stakeholders in

[1] https://www.accc.gov.au/system/files/LNG%20netback%20review%20-%20Final%20decision%20paper.pdf

the LNG sector GaffneyCline will apply subject matter expertise gained from its market interactions and market intelligence to inform the following areas:

a. LNG traders financial risk management activities, which typically involve hedging gas indexed short, medium and long term deals with derivatives based on the deeper oil market.

b. LNG contracting activities based on the "equity marketing" approach whereby LNG project participants enter into related party transactions with their own downstream/LNG marketing entities in order to meet project finance criteria. These transactions are frequently oil-indexed to meet lender requirements.

c. Global supply/demand trends, including marketing activities being undertaken by various entities which are likely to influence the pricing considerations of a buyer or seller over a 5 year forward period.

2. It is anticipated that within each 6-month reporting period, there may be a limited number of LNG sale and purchase agreements (with some degree of pricing transparency) which are based on an oil-indexed 5-year timeframe. To compensate for this small dataset this basic market data will be supplemented and fine-tuned using a toolkit of other market based inputs including:

   a. Global LNG Tenders, with a focus on oil linked tenders that are awarded, and those based on multiple deliveries over a period of months.

   b. Oil linked or hybrid LNG contracts for long term delivery.

   c. Correlations between crude oil prices and major gas indices, including those applicable to East Asia, Europe, and North America[2], which will serve to help to back-calculate oil equivalent prices.

   d. Long Run Marginal Cost (LRMC) of US LNG as a global price influencer, being the likely price setting source for new long-term LNG contracts (LNG Supply and Purchase agreements) for the next few years, providing a headline benchmark competitive price with Eastern Australian exports and which are likely to have some influence on LNG contract prices out to 5 years.

   e. Where relevant, back-calculated imputed oil indexation from government issued import or export pricing data may be adopted as a "look back" to correlate forecasts and fine tune methodologies.

The methodology is based on the following core assumptions:

- Gas will, in the long term, align pricewise with other energy products such as oil-derived fuels, coal and other combustibles that are measured in MMBtu of heating value. This is assumed to be true within the structural constraints that prevent a fully commoditised market for all energy products,
- Sophisticated energy industry players will typically seek to manage fuel price risk. Hedging gas price exposure is less accessible over the longer term than hedging oil. In this context, LNG traders and others exposed to significant price risk will use the much more developed, deeper oil market to hedge gas price exposure. This relationship between gas and oil prices will follow many of the features set out above,

[2] Including National Balancing Point (NBP), Title Transfer Facility (TTF), and Platt's Japan Korea Marker ™ JKM or its equivalent from other price monitoring services

and should therefore provide a mechanism for establishing the right approximate relationship between oil and gas.

It is envisaged that prior to each 6 monthly report, the relationships and correlations set out above would be reviewed and adjusted in order to maintain a current version of the methodology, suitably amended for market conditions.

The periodic reports will contain the following information:

- An overview of major LNG market developments and a qualitative review of how these affect the evolution of market prices, with particular reference to oil-linked prices going out to up to 5 years.
- A summary of LNG contracts entered into within the previous 12 months, with (where known or reported) key parameters listed including seller/buyer, start date, duration and pricing terms.
  - A subset of contracts considered appropriate as a direct basis for estimating contemporary oil-linked prices going out 5 years.
  - A subset of contracts or international tenders considered to be relevant in the determination of oil-indexed prices going out 5 years (which may have a term shorter or longer than 5 years, and may have a mix of different indexation terms)
    - Where relevant, analysis to standardise LNG pricing, considering a variety of different contractual terms such as volume flexibility, destination flexibility, and default/force majeure terms.
    - Statistical analysis and correlations with which to translate the pricing terms in the above category into oil-index equivalent terms.
- An overarching formula designed to translate the above information into an approximation of contemporary LNG pricing going out 5 years, expressed in oil slope terms.
- For the second and subsequent reports, an analysis of customs data will be included in a “look back” analysis to fine tune the overarching formula if necessary.

The following sections discuss the evolution of LNG pricing over recent decades, and provide context for the market-based LNG price indicators that will be used, where relevant, to supplement LNG transaction data. Section 9 sets out the proposed methodology for estimating medium term LNG prices.

Discussion

1 LNG Pricing History

The fundamental drivers supporting the relevance of oil indexation for LNG pricing derive from the first Asian LNG import contracts between Alaska and Brunei, and Japan. This was in response to the oil crisis of the early 1970s and a push to move away from dependence on crude oil-fired power generation, where switching to natural gas was an obvious policy move.

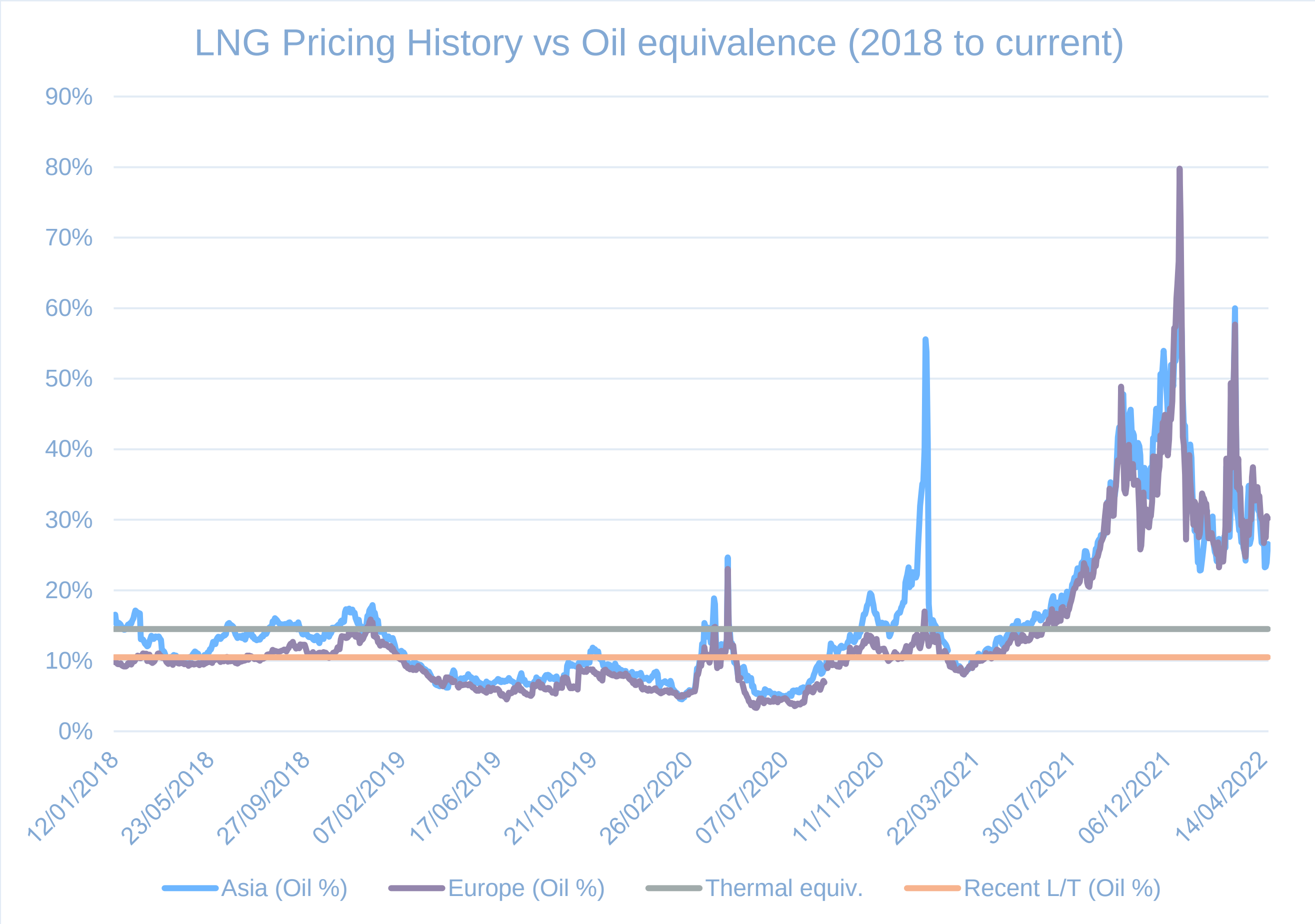
In thermal terms, there are approximately 5.8 MMBtu's of thermal energy in a barrel of oil, though the exact number depends on a variety of factors such as the oil quality. With LNG being priced in a MMBtu basis, this means that one MMBtu of natural gas is the equivalent of 17.24% (= 1 / 5.8) of a barrel of oil. However, because of the additional cost of handling LNG, and in particular the cost of plant and energy needed to regasify LNG ready for burning in a power station, the "oil equivalent" price of LNG was generally taken to be about 14.5% with a suitable adjustment for freight.

Thus, for many decades, most LNG contracts were priced using a slope of approximately 14.5%. Over time, several variations were also adopted, including the "S-curve". Under this arrangement, the slope decreases and is combined with a constant, for a range of oil prices that are either well above or well below typical levels envisaged by a buyer or seller at the time of contract pricing. Such a mechanism protects the buyer from disproportionately high natural gas prices, and protects the seller against disproportionately low revenues.

The other feature of many of these legacy LNG contracts was that they were typically fixed for a period of 15 to 25 years, and it is only relatively recently (say in the last 10 years) that features such as price reopeners or similar clauses have been adopted to enable buyer or seller to review the pricing under certain conditions.

While the relationship between oil and natural gas had trended downwards and had stabilised for a few years in the range of 9-11%, recent events have created a dislocation between oil and gas, such that natural gas price slopes have increased above this range as illustrated in Figure 1.

Figure 1: LNG Pricing History Expressed as Oil Equivalent



Source: ICIS, EIA, GaffneyCline Analysis

The recent increases in market volatility have also impacted the forward curve price correlations which are discussed in detail in Sections 5 & 6.

2 LNG Contract Database

Relevance to the Methodology

Although the LNG market lacks transparency, LNG trades are increasingly reported in full or in part. This dataset can inform the LNG pricing view through comparison with similar deals done in a similar timeframe.

Potential Limitations

Unlike many other commodities, LNG continues to be a traded under a variety of different and complex contractual arrangements. Individual contracts can sometimes contain price dependent features which are not apparent to those not close to the negotiations and direct price comparisons are therefore not always possible.

The primary source of insight for the six-monthly analysis will be data sourced from the Independent Commodity Intelligence Services (ICIS) LNG Edge LNG service[3], appropriately assessed, analysed and amended by GaffneyCline. The ICIS data is obtained from a number of sources, some public and some unidentified informants, and assimilated into a database on LNG trades, ship movements, and contractual developments. ICIS is used extensively by buyers, sellers, and project developers as an input to their decision making processes.

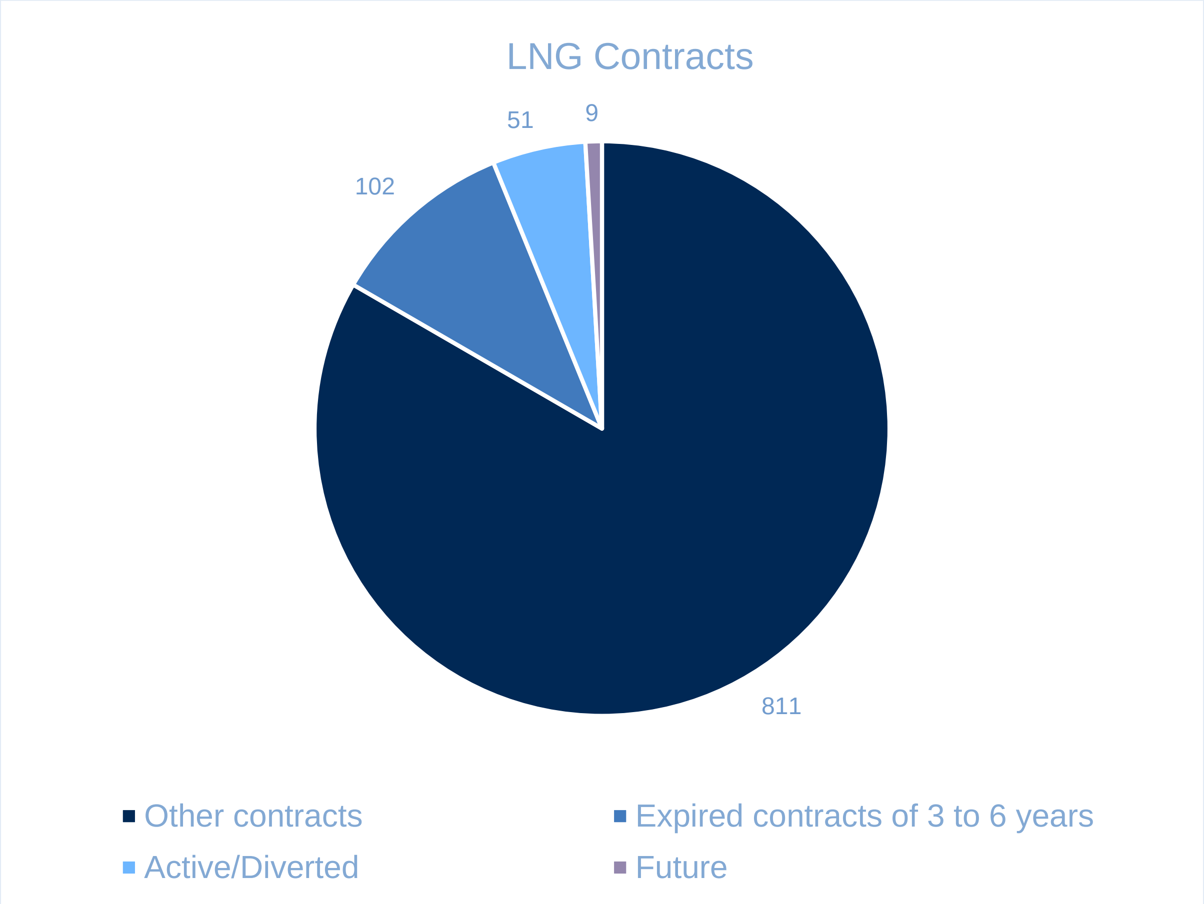
The basic data set contains information on over 1,000 LNG contracts of all lengths over the past 10 years. An analysis of the data set shows that about 160 of the total were of between 3 and 6 years in duration. Of those, about 51 are current, and 9 are due to start at some future date.

Examining the detail available it appears that 14 of the 60 current or future contracts are confirmed to have oil price indexation in the price, and the slope is reported for 8 of them. The average slope stated is 12.64% with a standard deviation of 1.24%.

One future contract was signed within the last 12 months with a slope of 11.2%.

[3] https://www.icis.com/explore/services/analytics/lng-edge-and-pricing-data/?intcmp=services-lng-market-intelligence-solution_lng-edge-and-pricing-data

Figure 2: Breakdown of LNG Contract Database



Source: ICIS/GaffneyCline Analysis

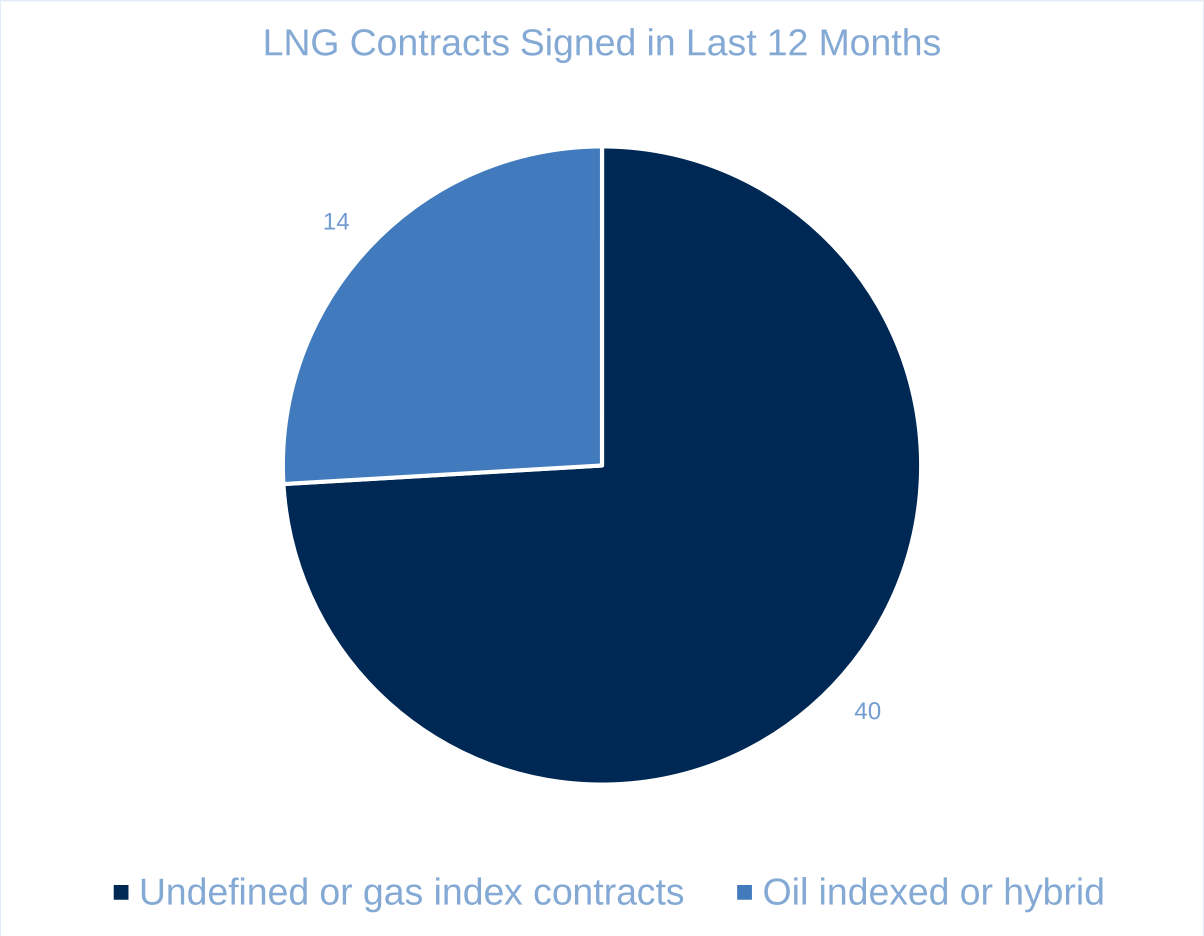
About 54 new LNG contracts were entered into in the last 12 months. Of these recent contracts, 14 were reported to be indexed to oil, or to have oil present in the indexation formula.

Of those 14, slope data is present for 6 of them, and their average contract duration is 15 years.

Only one oil or hybrid contract was signed with a duration of less than 7 years.

What we conclude from this analysis is that the contracts that can directly inform a view on oil-indexed pricing up to 5 years out are likely to be very small in number.

Figure 3: Proportion of Oil linked or Hybrid Contracts in Last 12 Months



Source: ICIS/GaffneyCline Analysis

3 Long Term Contracts

Relevance to the Methodology

Long Term LNG contracts are more likely to contain oil indexation as this methodology continues to find favour with major lending institutions. Reported pricing can be used to inform oil indexation for medium term (circa 5 year) contracts.

Potential Limitations

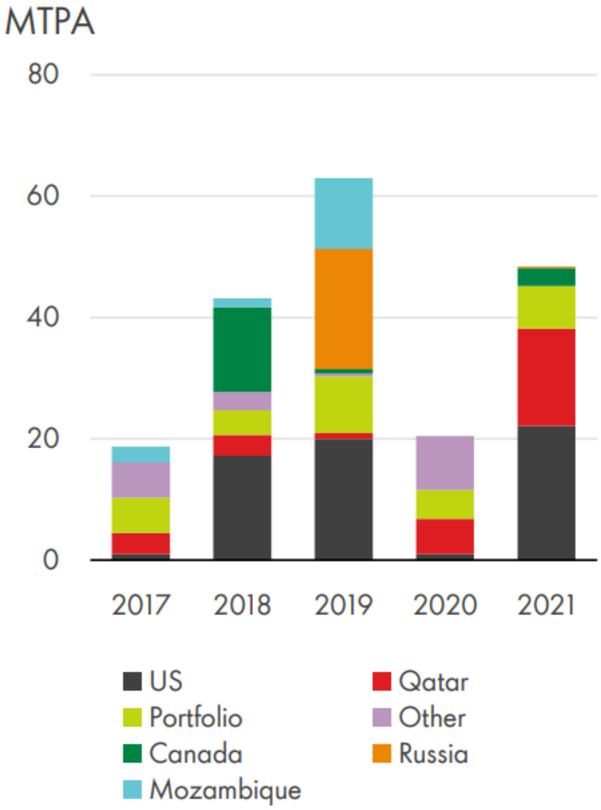
Long Term contracts are often used to underpin lending arrangements. Oil indexation levels are therefore likely to be lower than for short or medium term contracts.

Although the COVID pandemic eroded demand for LNG and accelerated the gradual price erosion that had taken place since about 2018, the overhang of LNG in the market, largely as a result of the rapid increase in US exports, had become a structural feature of the market.

Over this period, strategic gas buyers had become comfortable with a larger share of their gas purchases being through short- or medium-term obligations. However, the market tightness of the last few months has spurred a number of buyers to once again seek supply commitments of 15-20 years. The data below from the Shell LNG Review for 2022 shows an uptick in long term deals in 2021 which is likely to show a continuing increase for 2022.

Another effect visible in this trend is the hiatus in FID decisions for new LNG projects during the period of very low prices which resulted both from buyer hesitation to entertain oil-indexed pricing and the lack of willingness of lenders to fund new developments, based on the index pricing that buyers preferred (on account of the lower resulting price).

Figure 4: Term Deals for LNG by Year



Source: Shell

Contracts signed in the first quarter of 2022 are typically in the range of 10.2% to 10.85% of oil prices, which represents a range of buyer/seller relationships and terms.

GaffneyCline estimates, based on likely implications for cost of debt, that allowing for the benefits that accrue to a project developer through securing a long-term offtake, a medium-term contract (with a counterparty of similar creditworthiness) might result in a 5% price premium over a 15- or 20-year timeframe.

4 Short to Medium Term Tenders for LNG

Relevance to the Methodology

Short Term LNG contracts are more frequent than medium- or long-term contracts, and therefore provide a larger number of data points from which to derive a view of market pricing.

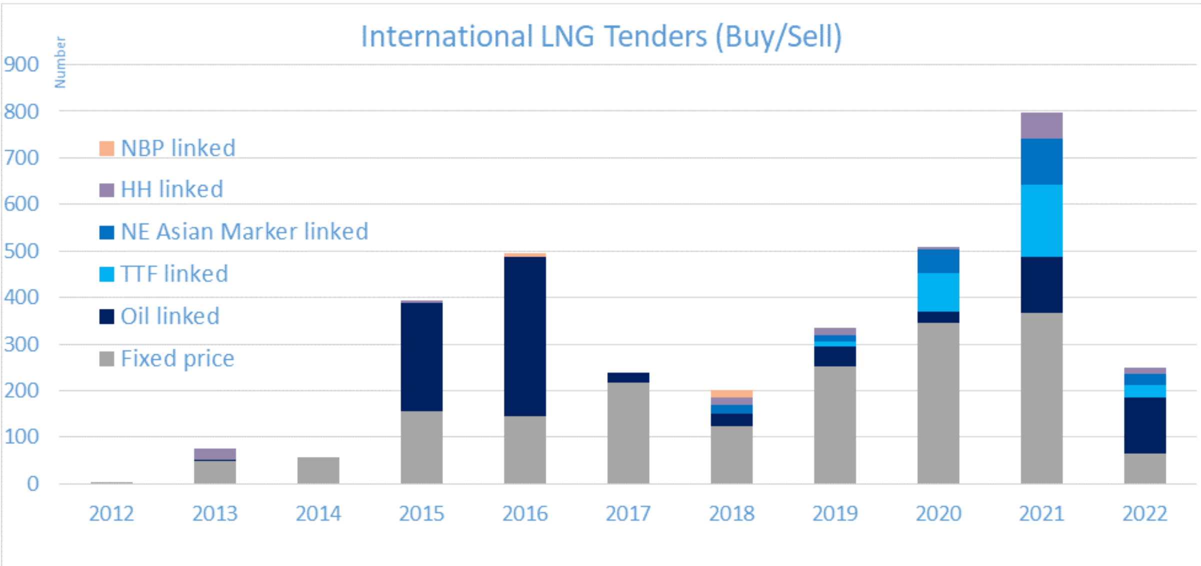
Potential Limitations

Most short-term contracts or tenders are for LNG purchases in the months following the deal. They tend to be influenced by short term supply/demand dynamics which make the data derived less statistically significant to a 5-year view, especially during periods of volatility.

To provide a balance in the LNG market, including shorter term buyer requirements (caused by e.g. weather, uncontracted gas production from liquefaction facilities), and to facilitate the traded LNG market, from time-to-time buyers, sellers and traders will offer public or semi-public tenders for LNG. These can be a "buy" or a "sell", on either an FOB or DES basis and can be anything from a single cargo, to batches of multiple cargoes stretching sometimes further than one year.

The chart below shows the breakdown of international LNG tenders (by number), and on what basis they were settled:

Figure 5: LNG Tender Indexation Type



Source: ICIS/GaffneyCline Analysis

The data demonstrates that oil continues to be adopted as a feature in the pricing basis for LNG tenders, often combined with other indices. Certain buyers also favour oil over gas indices.[4]

It is noteworthy that where a tender involves multiple deliveries (typically >10) oil indexation is a more popular form of pricing and this has been evident in the first 4 months of 2022. One of the reasons for this is the relative ease and low cost of hedging fuel costs priced on oil, compared to gas indices, particularly in light of recent volatility.

A detailed breakdown of contract data is illustrated in Table 1.

Table 1: Cargo Summary 2012-2022

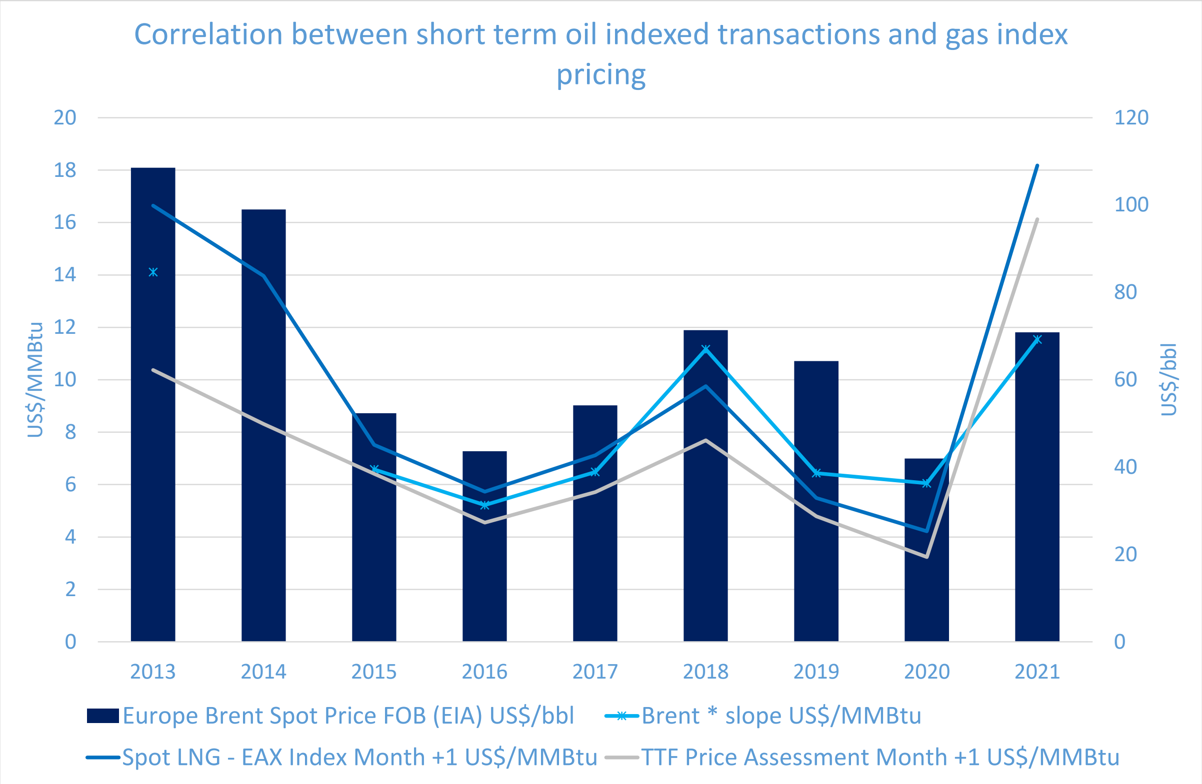
Year	*Cargoes ICIS informed as oil linked price*	*Cargoes ICIS informed as NE Asian Marker linked price*	*Cargoes ICIS informed as TTF linked price*	*Cargoes ICIS informed as HH linked price*	*Cargoes ICIS informed as fixed price*	*Cargoes ICIS informed as NBP linked price*
2022	120	24	26	13	65	0
2021	120	98	154	58	368	0
2020	24	50	82	6	346	0
2019	42	15	11	16	252	0
2018	27	18	0	18	123	14
2017	22	0	0	0	216	0
2016	342	0	0	0	144	10
2015	232	0	0	5	157	0
2014	0	0	0	0	56	0
2013	2	0	0	24	49	0
2012	0	0	0	0	1	0
TOTAL	**931**	**205**	**273**	**140**	**1,777**	**24**
Total Cargoes ICIS Database	7,876					
No Price info available	4,525					

Source: ICIS/GaffneyCline Analysis

The lack of commoditisation in the LNG industry is demonstrated in the Figure 6, which shows that correlation between oil slopes and average forward prices for LNG (Asia and Europe) can change over time. While they exhibited a reasonably strong correlation over the period from 2015 to 2019, this correlation weakened over 2020 and 2021.

[4] HH = USA Henry Hub, NBP = UK National Balancing Point, TTF = Dutch Transfer Title Facility, JKM = Japan Korea Marker

Figure 6: Oil Slope Correlation with Gas Indices (s/t tenders)



Source: ICIS/GaffneyCline Analysis (Note: Brent * slope is derived from buy/sell tenders that were awarded in each respective year – no data available for 2013/4)

The data further demonstrates that in the 2014 to 2017 timeframe, there was good correlation between short term oil indexed transactions and gas index pricing.

5 Correlations between Oil and Major Gas Indices

Relevance to the Methodology

The fundamental supply dynamic of LNG is very different to oil, and the two commodities are increasingly de-linked. This has implications when estimating of LNG prices linked to oil prices, and the basic relationship between global gas indices and global oil prices is therefore a highly relevant feature of the analysis, enabling the theoretical thermal equivalent pricing of oil and gas to be amended based on the market.

Potential Limitations

Because the LNG market is illiquid and has been subject to considerable volatility from time to time, the correlations must be applied with caution and are only a guide to the relationship between oil-indexed pricing 5 years out and gas index forward curves.

In a fully commoditised and liquid market for LNG, it would be expected that European, Asian and North American gas indices (for example JKM, TTF and Henry Hub) would align and correlate closely, save for an adjustment for freight, fuel and regas costs, as the case may be.

However, given the development of natural gas markets over the last few years, and as natural gas has slowly disconnected from oil as a result of more LNG flowing around the world in response to prices, these correlations have varied.

The correlation between Asian and European gas index prices and Brent crude since 2012 was 65% and 43% respectively. However, the data since January 2021 shows a much higher correlation of 70% and 77% respectively.

Conversely, the volatility in gas index prices over the period from January 2021 to April 2022 showed a standard deviation of over $12/MMBtu, which introduces potentially material hedging costs for natural gas compared to oil, which may drive buyers/sellers and traders back to using an oil slope, with a standard deviation of only $2.54/MMBtu.

The correlations and volatility are shown below, for 4 periods of time. By comparison with the graph below, the relationship between oil prices, European and Asian gas indices can be noted:

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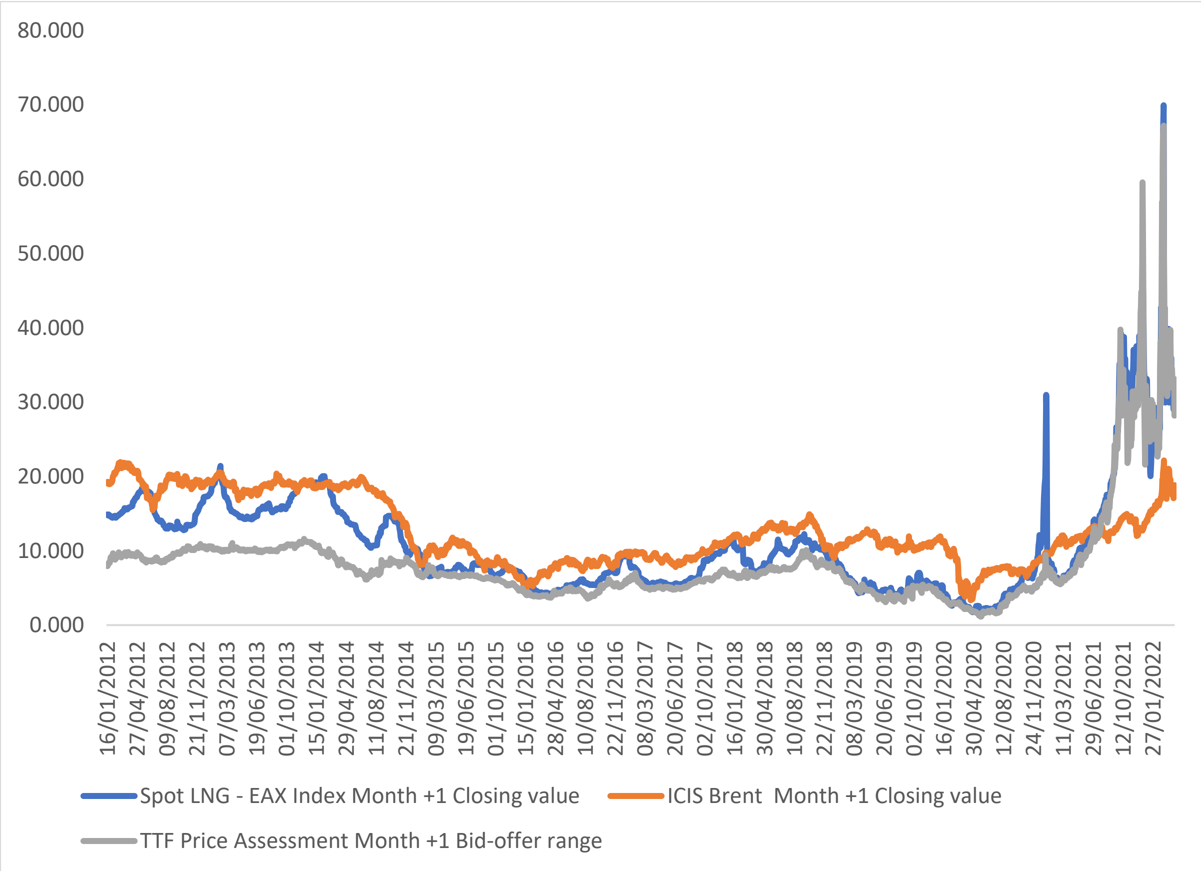
Table 2: Correlations and Volatility of Oil and Gas Indices

Period	Correlation EAX with Brent	Correlation TTF with Brent	EAX Volatility (Std. Dev.)	TTF Volatility (Std. Dev.)	ICIS Brent (Std. Dev.)
Jan 2012 / April 2022	**0.65**	**0.43**	**7.18**	**6.63**	**4.46**
Jan 2012 / Dec 2014	0.45	0.30	2.54	1.17	1.95
Jan 2015 / Dec 2020	0.58	0.65	2.32	1.70	2.12
Jan 2021 / April 2022	0.70	0.77	12.04	12.58	2.54

Figure 7: Oil and Gas Historical Relationship



Source: ICIS/GaffneyCline Analysis

6 Long Run Marginal Cost (LRMC) for US Exports

Relevance to the Methodology

The US has emerged as the likely “swing” supplier of LNG to global markets for the foreseeable future. Given its highly competitive nature, the cost of producing, liquefying, and delivering US LNG to global markets is likely to have some influence on contemporary Asian LNG contract prices and form a price ceiling in the long term (although possibly beyond a period of 5 years).

Potential Limitations

LNG projects require many months in the planning, regulatory and construction phase, and periods where demand exceeds supply may weaken the influence of US export LRMC on Asian LNG prices and thus create LNG prices/oil slopes that generate a price greater than the LRMC of US exports.

6.1 US LRMC Influence in the 3-5 Year Timeframe

The US natural gas industry has three major features which will place it in a pivotal role for global LNG for the foreseeable future:

- A very large proven gas resource which can be developed at a relatively predictable and stable cost.
- A favourable regulatory regime and receptive demographic which places few major constraints on future LNG export terminal development (in the Gulf Coast region).
- A very liquid and deep wholesale market for natural gas, and a highly competitive industry which readily establishes a market clearing price for gas, and increasingly LNG.

As a result of this, active buyers and sellers in the LNG market are likely to consider the influence of the LRMC of US exports when entering into LNG sales or purchase commitments, particularly where these commitments have the potential to generate pricing in excess of the likely long run marginal cost of LNG from the US. LNG market participants are likely to also consider other factors, such as prices arising from shorter-term LNG tenders.

For example, an LNG buyer may determine the likely cost stack based on LNG exports from the US (see section 6.2 below) and compare it with longer term expectations and forward curves for oil to arrive at an oil slope they believe will be roughly equivalent (adjusted for various contract terms and hedging costs). Sellers may place a greater weight on short-term international LNG tender prices when considering prices for 5-year LNG contracts.

With an efficient supply chain and an increasing track record, new supplies of LNG can be offered on an increasingly short timeframe, and some of the recent examples, such as the Venture Global project that was able to achieve first LNG production within 29 months of FID.

With the announcement of a US/EU Commission on Reducing Europe's Dependence on Russian Fossil Fuels[5] it is likely that additional resource may be put into increasing US LNG exports in the coming years, which may accelerate the envisaged medium to long term linkages between US and global LNG prices.

As such, US LRMC is somewhat likely to influence LNG pricing in the 2-5 year timeframe and may therefore be an influence on oil slope determination in the period on which this report is focused.

6.2 Role of US LNG in Global Markets

For the reasons set out above, US LNG exports are likely to dominate new project FIDs for the next 10 years or more, alongside additional expansion plans in Qatar. Australia has arguably passed the high growth stage, and although Russia held a lot of promise, the recent conflict with Ukraine has at least deferred if not cancelled substantial expansion plans. Several buyers who were planning offtake from the Russian projects are now seeking alternatives. This could mean that there will also be potential opportunities for substantial gas finds in East and West Africa. Competition will also emerge from expansion and debottlenecking of existing terminals.

Oil and natural gas markets pre-2013 were relatively well correlated in terms of price. Although the world LNG market had previously been dominated by an LNG price based on a percentage of the oil price (i.e. the "slope"), the early US LNG export contracts contained a radically different price determining mechanism. The innovative US mechanism was designed to give the developer of the liquefaction plant a steady and assured rate of return, usually under what is termed a 'tolling contract', with all the gas price risk assigned to the buyer. In such a pricing formula, there are typically four elements to consider when determining the cost of delivering LNG to the customer:

- One of the most material features of that cost is the price of natural gas that enters the liquefaction plant, ultimately to become LNG. Given the highly developed nature of the US wholesale market, this is almost always features the Henry Hub (HH) index, which is the primary price marker for gas in the United States. Therefore, this is the first of the building blocks used to determine the delivered price.
- The pricing will also include a charge to address both the fuel used in the liquefaction train, which leads to a loss of gas between delivery into the plant and onto the ship, and any possible basis differential between HH and the location of the plant. In most of the early tolling agreements, these two features were determined as a 15% surcharge on the HH price adopted. Thus, the HH element of price changes according to the prevailing price in the US market, and is aggregated to 115% of HH, to encompass the two factors above.
- The third element in the pricing, of a similar order of magnitude to the HH index arrangement, is the so-called 'toll' which equates to a lease on the seller's liquefaction facilities. This toll can be seen as a function of the return required by the seller to

[5] https://www.whitehouse.gov/briefing-room/statements-releases/2022/03/25/fact-sheet-united-states-and-european-commission-announce-task-force-to-reduce-europes-dependence-on-russian-fossil-fuels/

compensate for the capital investment in the liquefaction trains, storage tanks and marine facilities which are used to treat, liquefy, and store the feed gas. This element of the price formula is fixed and has typically been in the range of $2.00–$3.25/MMBTU.

- Finally, there is a freight charge which the buyer must address, which represents the cost of moving the LNG from the seller's terminal facilities in the United States to those of the buyer. Many of the early LNG long-term SPAs are based on a free-on-board arrangement which means that the delivery point is the flange at the liquefaction terminal in the United States, where the LNG passes on to the LNG carrier, provided by the buyer. This part of the charge is a function of the shipping arrangements entered into by individual LNG buyers, but is often influenced by LNG carrier charter rates, especially for those companies without ships under long-term time charter.

Thus, by aggregating the cost of LNG delivered to the buyer, it amounts to the following:

115% of HH + liquefaction toll + freight to the buyer's regas terminal

The important consideration is that both the structure of the formula, and the quantum arrived at, are very different from the typical oil indexed formula that an Asian buyer might have entered into prior to US LNG export availability.

The attraction to an Asian buyer was therefore threefold:

- mitigating the exposure to global oil prices, which had led to very high LNG prices during eras of high oil prices;
- diversifying LNG price to a commodity with only a weak correlation to global oil prices; and
- offering a much higher proportion of fixed, or less variable features of, price, thereby reducing expected price volatility compared to oil (although arguably S-curves or cap/floor arrangements in LNG SPAs achieve a similar effect).

With the wide adoption of "gas on gas" pricing, arguably gas prices in the United States and Continental Europe are now close to reflecting the fundamental value of natural gas, rather than a previous reliance on oil linkage. Therefore, as North American shale gas continues to make its way into global markets, the efficiencies of a gas-on-gas competitive environment will impact global gas pricing, and a global clearing price, influenced largely by regional gas costs and freight charges, will emerge.

The impact of this has become increasingly apparent during 2021, when the US took its place as the world's leading LNG exporter. The pricing volatility of end-2021 and early 2022, have also resulted in cargoes perhaps initially destined for Asia, being diverted, sometimes mid journey and sometimes more than once, to re-route to the highest priced market, which has typically been Europe given current security of supply concerns.

With this greater interconnection between markets, with LNG carriers becoming more and more responsive to price arbitrage, TTF and JKM prices have exhibited a high degree of correlation recently. A substantial increase in US liquefaction capacity, for example, might cause TTF and JKM to be more strongly influenced by Henry Hub based LNG export pricing in the future, based only on the differences in freight charges (provided sufficient liquefaction capacity is added).

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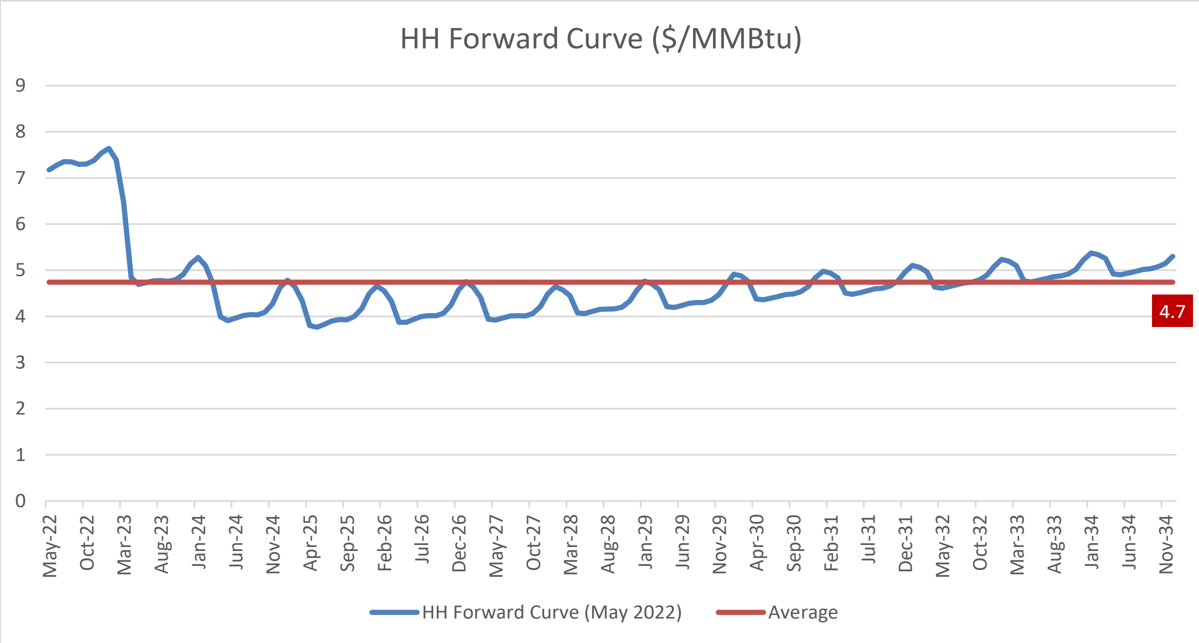
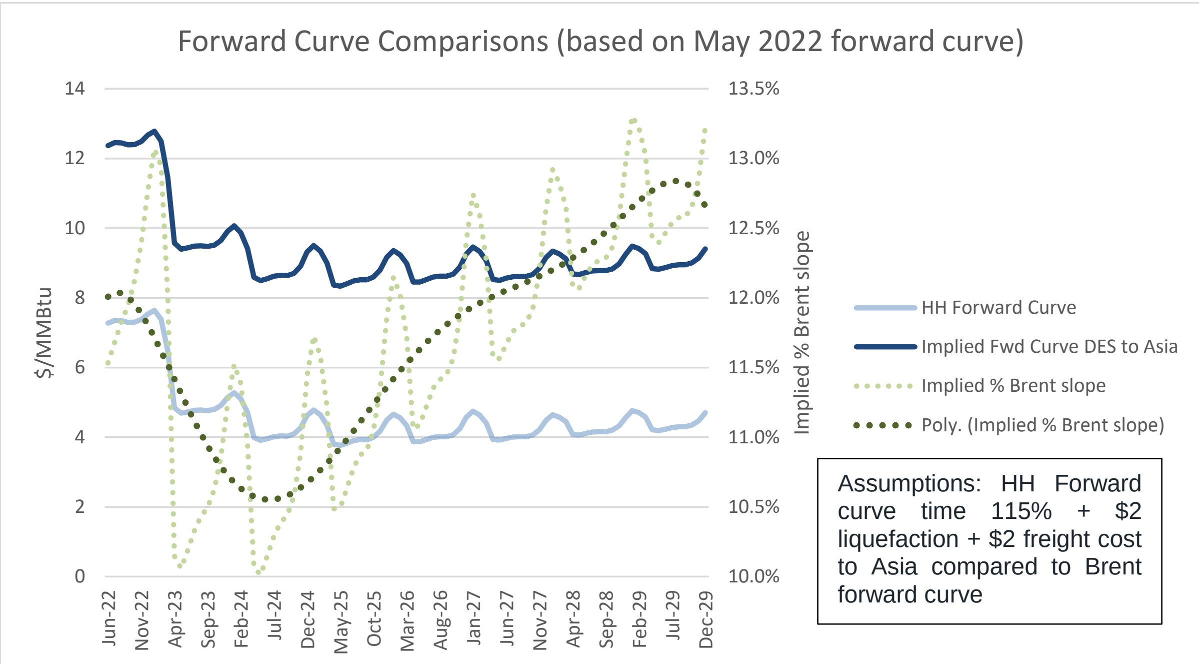
The derivation of Henry Hub based US LRMC will be based on the methodology set out below:

Figure 8: Henry Hub Forward Curve



Source: ICIS/GaffneyCline Analysis

Figure 9: US LNG LRMC Expressed as Implied Oil Slope



Source: ICIS/GaffneyCline Analysis

Figure 9 suggests that in the medium term, a derived oil curve based on LRMC from the US may be below oil linked formulae (using May 2022 forward curve), suggesting that global markets are likely to respond to an excess of demand over supply. In such periods, actual LNG contract prices out to 5 years may be more influenced by broader demand and supply dynamics and thus sit above the LRMC of US exports.

In practice, the influence of the LRMC of US LNG exports is likely to vary over time, and will be only one of several factors that influences LNG contract prices.

7 Customs Records

Relevance to the Methodology

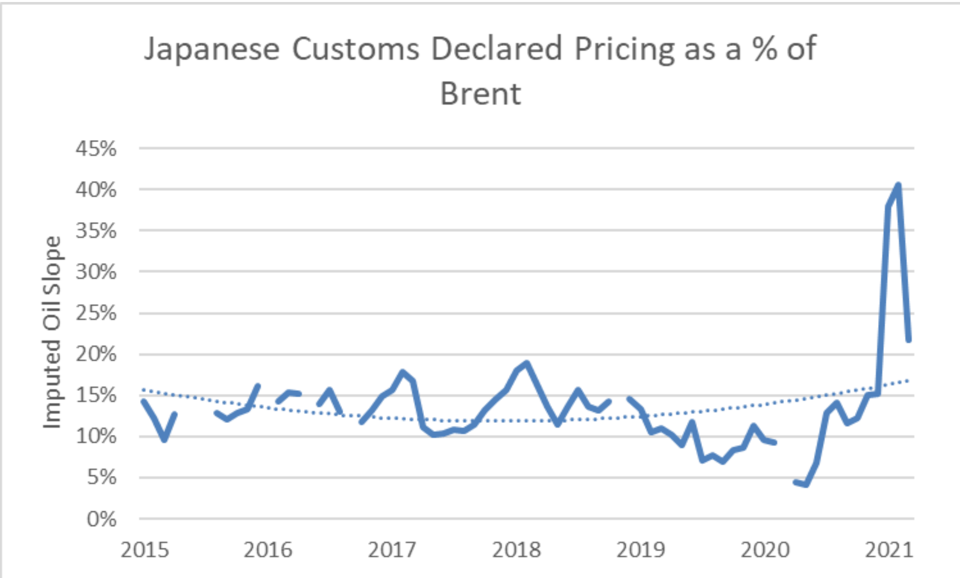
Customs data, such as that published by METI in Japan, and the US Dept of Energy, provides historic data that may be valuable in a retrospective analysis of the contemporary analysis provided by this methodology.

Potential Limitations

Multiple forms of contract are commingled to produce delivered prices, so the analysis can be used to determine trends only.

Analysis of customs records, such as those provided by METI are problematic with respect to determining contemporary pricing or forecasts in that they represent a blend of long, medium- and short-term transactions that include a range of price formulae.

Figure 10: Correlation of Oil Index and Customs Data



Source: METI/GaffneyCline Analysis

Customs data is considered a potentially useful general guide and checking feature with which to establish a sense checking feature to the methodology but is not considered reliable enough on its own to include in the proposed oil slope derivation.

8 Reconciliation of Differing Contract Terms[6]

Given the lack of transparency in the LNG industry and the confidentiality applied to contracts, it is unusual for the full details of contracts to be made public. However, where this has been done (to comply with government/regulatory requirements for example), it will be possible to amend oil slope data, prior to combination in the proposed methodology, based on the following.

Enabling an "apples to apples" comparison between different LNG offtake agreements requires a sophisticated understanding of LNG SPAs and the commercial relationship between the terms in the contract, and the price a buyer or seller might be willing to settle at. The methodology used for the ACCC report content will include the following:

- FOB offtake versus DAT: In addition to the basic cost of freight, control over the shipping logistics creates optionality for an FOB buyer. This optionality can be modelled using a series of market-based features such as regional price volatility, geopolitical factors, and LNG supply resilience to arrive at a price factor in $/MMBtu (or percentage oil price) to reconcile one type of contract with another. The outcome of this part of the analysis will be an upward or downward price adjustment based on FOB or DAT.
- Destination Flexibility: Even with a DAT/DES contract, some level of destination constraint may exist, or a "profit sharing" mechanism may mean that the optionality around destination does not deliver full value for the seller. This would be another feature that would be used to derive price implications to reconcile one contract with another. While this factor would change for each six-monthly report, an adjustment in $/MMBtu, or equivalent oil slope adjustment, would be applied to bring all the reported prices into a standard form.
- Buyer failure to take/Seller failure to deliver: Contracts can deal with default in different ways, which may include one party taking reasonable steps to mitigate damages or may include not only direct but consequential damages. Assigning a probability and cost to these hypothetical occurrences is necessary to arrive at a true underlying price for the LNG, and would be re-calculated for each report, based on the then current market conditions.
- Downward and Upward flexibility: Many medium-term contracts these days contain a much higher degree of buyer flexibility than has previously existed. This can include a shorter timeframe within which to fix a delivery program (e.g. 90 days as opposed to the traditional annual program), and may include a buyer's ability to cancel or move a cargo at short notice. These features impact the likely revenue/profitability for the seller and are therefore factored into pricing levels. Comparing different levels of volume flexibility requires a detailed understanding of global markets, buyer/seller sentiment at any given time, and a detailed algorithm capturing LNG marketing decision making and likely outcomes. These algorithms, the logic behind which would be published in detail in our initial report on methodology, would be rerun for each six-monthly report.
- A range of other features can also be relevant to price, and over the duration of the proposed ACCC reporting period, these may increase or decrease in importance and impact how the price reconciliation methodology is applied. These changes in the LNG

[6] A detailed explanation and price conversions are attached in Appendix II.

market environment, and how they impact methodology, will be fully documented in each revision of the price outlook.

9 Proposed Methodology

Based on the analysis set out above, three main sources of insight can be applied to understanding contemporary LNG contract pricing, in addition to reported contracts of the duration of interest (3-6 years). These are:

1. International tenders
2. Long term contract signings
3. Long run cost of US LNG Exports

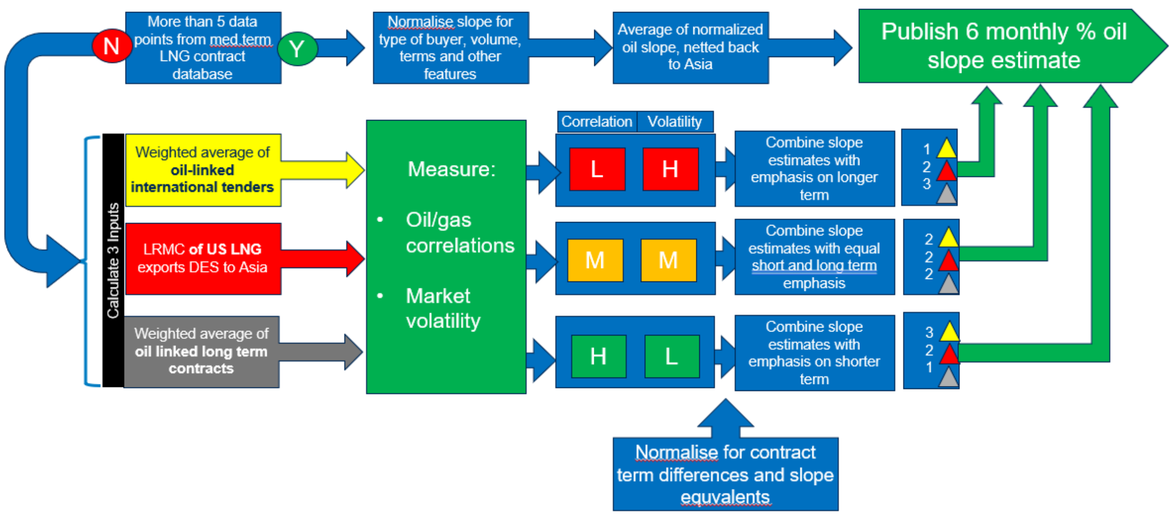
The discussion in the sections above demonstrates that the relationship between these three sources of insight varies, based on the market conditions prevailing. For example, when there is considerable volatility in the market, shorter term/international tender prices can depart substantially from longer term market fundamentals, and are less helpful in signalling an oil slope up to 5 years out.

Conversely, when the market is very well correlated, and volatility is low, tender prices are a much better signal for a 5 year look ahead and deserve greater emphasis in the approximation process.

When average levels of correlation / price volatility apply, a 5 year look ahead is likely to be equally affected by shorter term, longer term, and calculated long run costs of LNG delivered from the US.

The proposed methodology is illustrated schematically below:

Figure 11: Methodology Flow Diagram



The proposed methodology and derivation of approximate 5-year oil-linked LNG slope is set out in more detail below:

1. If there is sufficient data that can be sourced for medium term LNG contracts (e.g. 5 or more transactions with full or partial reported oil slope within the previous 12 months), then the volume weighted average of these slopes will be used as the primary input derive LNG oil slope estimates.
2. If there is insufficient data from this source, then any price points that can be sourced (if any) pursuant to #1 above will be modified using the following approach:
    a. Calculate the volume weighted average of internationally tendered cargoes linked to oil
    b. Calculate the long run marginal cost of US LNG exported to Asia
    c. Calculate the volume weighted average of any long-term contracts linked to oil
3. In an environment where oil and gas indices have experienced high volatility and have been **less than 40%** correlated within the previous 12 months: Combine the oil slope derived from (1) and the coefficients calculated from 2 (a), (b) and (c) in the proportions 1:2:3, thereby placing more emphasis on longer term deals
4. In an environment where oil and gas indices have experienced average volatility and have been more than **40% and less than 60%** correlated within the previous 12 months: Combine the oil slope derived from (1) and the coefficients calculated from 2 (a), (b) and (c) in equal proportions to calculate an overall oil slope
5. In an environment where oil and gas indices have experienced low volatility and have been **more than 60%** correlated within the previous 12 months: Combine the oil slope derived from (1) and the coefficients calculated from 2 (a), (b) and (c) in the proportions 3:2:1, thereby placing more emphasis on shorter term deals.

Worked examples to illustrate the methodology are included below. ***Example 1*** shows how the oil slope would be derived, based on 6 example contracts for which oil slope data is available:

Table 3: Worked Example 1

Example Contract	*Volume (MMtpa)*	*Slope adjusted for terms and delivery point*
1	*0.5*	*11.0%*
2	*1.25*	*11.5%*
3	*1*	*10.0%*
4	*0.35*	*10.2%*
5	*0.8*	*10.4%*
6	*1*	*12.0%*
Total volume / Weighed average	*4.9*	*11.0%*

In this example, the contracts range between 10% and 12% in indexation (adjusted for contract terms where appropriate) and from 0.35 to 1.25 MTPA in annual quantity. The resulting price slope is 11%.

Example 2 shows a more likely scenario, where only limited contract data has been obtained, in this case from 3 example contracts. Depending on the degree to which oil and gas prices are correlated, there are three different scenarios for deriving the relevant oil slope. The three example scenarios involve an oil/gas correlation of 50% (average), 35% (low) and 65% (high correlation, and therefore each hypothetical scenario places a differing emphasis on short- and long-term contract pricing:

Table 4: Worked Example 2

Example Contract	Volume (MTPA)	Slope adjusted for terms and delivery point
1	0.5	11.0%
2	1.25	11.5%
3	1	10.0%
Total volume / Weighed average	2.75	10.9%
Volume weighted international tenders		13.1%
Volume weighted long term deals		10.3%
LRMC US exports converted to slope		9.5%
Oil/index correlation 50%	Averaged slope	10.9%
Oil/index correlation 35%	Averaged slope	10.7%
Oil/index correlation 65%	Averaged slope	11.1%

Depending on how markets have behaved in the 12 months prior to the price determination, the oil slope could be between 10.7% and 11.1%. GaffneyCline will provide its recommended approximate slope, based on our market assessment.

It is envisaged that as LNG markets and the half yearly report evolve over the coming months, the methodology could be revised and simplified.

Appendix I
Glossary of Terms

List of Standard Oil Industry Terms and Abbreviations

ACQ	Annual Contract Quantity
A$	Australian Dollars
Bbl	Barrels
/Bbl	per barrel
BBbl	Billion Barrels
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
Bm^3	Billion cubic metres
boe	Barrels of oil equivalent @ xxx mcf/Bbl
boepd	Barrels of oil equivalent per day @ xxx mcf/Bbl
BTU	British Thermal Units
CAPEX	Capital Expenditure
DAT	Delivered At Terminal
DCQ	Daily Contract Quantity
DES	Delivered Ex Ship
FDP	Field Development Plan
FEED	Front End Engineering and Design
FID	Final Investment Decision
FOB	Free on Board
GBP	Pounds Sterling
HH	Henry Hub (US gas hub price)
ICIS	International Commodity Intelligence Services
JKM	Platts Japan Korea Marker (TM)
LNG	Liquefied Natural Gas
m^3	Cubic metres
Mcf or Mscf	Thousand standard cubic feet
MMcf or MMscf	Million standard cubic feet
m^3d	Cubic metres per day
Mm^3	Thousand Cubic metres
Mm^3d	Thousand Cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
Mscfd	Thousand standard cubic feet per day
MMscfd	Million standard cubic feet per day
MMtpa	Million tonnes per annum
NBP	National Balancing Point (UK gas hub price)
p.a.	Per annum
cfd or scfd	Standard Cubic Feet per day
scf/ton	Standard cubic foot per ton
SL	Straight line (for depreciation)
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
ss	Subsea
T	Tonnes
TD	Total Depth
Te	Tonnes equivalent
THP	Tubing Head Pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TTF	Title Transfer Facility (NL gas hub)
TOP	Take or Pay
US$	United States Dollar

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Appendix II
Methodology for Normalising Contract Terms

Australian Competition & Consumer Commission
3rd May 2022

The negotiation of a major Sale and Purchase Agreement between an LNG seller and buyer will typically be examined on a sophisticated basis, with each side taking advantage of a support group whose role it would be to quantify the financial implications of various terms and conditions contained in the contract.

A firm LNG offtake by an FOB buyer would be priced according to the following features and variables:

- ACQ. Base project economics would be based on an expectation that the buyer would undertake to purchase a quantity of gas equal to the ACQ. This would then be inputted into the master project economic model, which would generate a project return, which may be further subdivided into an equity return, based on the fixed portion of debt that may be present, and the cost that had been negotiated.
- The starting point for the model would most likely be an approach that contains some reasonable degree of contract flexibility, coupled with what might be considered a "market price" for LNG at the time. Given the timing of the contract under review, this would be based on oil indexation, somewhere in the mid to high 14%. Variations from these typical flexibility terms would be evaluated to determine whether a lower or higher indexation level would be appropriate.
- The considerations that the seller would bear in mind are set out below, and a basic assessment of the order of magnitude of each feature, in terms of changes to the price and oil indexation needed to generate similar economic returns, is set out at the bottom of the discussion.

With this base case in mind, the sellers would examine the various features of the contract and may assign a change in the project returns, which could be translated into a pricing discussion to be had with the counterparty.

The methodology involved in assessing a price change resulting from a number of the key contract parameters could be viewed as follows:

- FOB versus DES. The seller may take the view that using an FOB sales basis would preclude the sellers from organizing their shipping fleet to take advantage of operational synergies, fast or slow steaming, or other mechanism that could either save on the cost of freight or result in a slightly higher average cost of gas sold.
- Lack of diversion rights/profit sharing clause. An FOB offtaker who is in the business of LNG aggregation and trading would not typically agree to any restrictions on LNG destination or sales price, as might have been the case with a utility buyer (FOB or DES). As such, the seller would not benefit from periodic sales of LNG on a spot basis at prices higher than the contract price. This represents an opportunity cost, therefore. The basis for assessing this opportunity cost might be an assumption that a small portion of LNG sales could be redirected, and that the seller might share any net profits under a 50/50 arrangement.
- Downward Flexibility Quantity (DFQ). If the buyer is offered the option to reduce the ACQ by a DFQ, the seller would typically make an assumption around the frequency and amount by which the ACQ might be reduced and rerun their project model based on that lower sales volume. This could then be translated into an equivalent higher base price, to keep the seller's economics "whole". Some allowance may be made for being able to insert a spot cargo into the ADS, to partially compensate for the lack of

cashflow as a result of the buyer using their DFQ, but the assumption would be for a lower price, given the short term nature of the cargo, which might, for example, be sold through a tender.

- Upward Flexibility Quantity (UFQ). The opportunity cost for the UFQ is more complex to address as the existence of the UFQ means that up until the ADS is agreed, the seller would need to put aside sufficient capacity to be able to offer UFQ in the first place, unless the obligation to make it available is on a reasonable endeavours basis only. Typically, a reasonable endeavours obligation to supply gas would be classed as excess gas. As with the DFQ, some assumption might be made that if the buyer does not exercise their UFQ, then that same quantity of gas could be offered for sale on a short term/spot basis.
- Excess Gas. Most LNG facilities are capable of operating beyond their nameplate capacity, especially after one or two years of operation, and so buyers have the opportunity to take excess gas. Where excess gas is priced at the contract price, it represents a boost to project economics, as its marginal cost of production is less, and typically excess gas would only be marketed on a short term/spot basis as the seller would typically be uncomfortable selling it on a long term/committed basis (especially prior to any formal debottlenecking process).
- Other factors that may influence price include whether the project is in development phase, or whether LNG is being re-marketed following the end of a previous contract, geopolitical risk and security considerations, and whether the buyer has equity participation in the project.

Scenario	***Assumption (based on 14.8% JCC with typical levels of flexibility)***	***Price implication $/MMBtu***	***Price implication %JCC***	***Price implication %JCC***	***Resulting indexation***	***Resulting indexation***
			$50 oil	***$80 oil***	***$50 oil***	***$80 oil***
Base price inexation with no flexibility by seller and control by the buyer over shipping efficiencies	13.75		$ 7.40	$ 11.84		
FOB basis for sale compated to DES	A 5% saving in freight costs by being able to control shipping logistics	$ 0.09	0.17	0.31	13.92	14.06
Lack of diversion rights	Assumes that 1 in 20 cargoes could be sold for an additional $1/MMBtu	$ 0.03	0.05	0.09	13.80	13.84
Downward flexibility quantity	A 10% buyers option to reduce the ACQ with no mitigation from spot sales with no price or volume mitigation	$ 0.17	0.31	0.57	14.06	14.32
Upward flexibility quantity	A 10% buyers option for a firm commitment to deliver 10% more than the ACQ with the potential to mitigate by selling the equivalent on a short term basis at a $1/MMBtu discount	$ 0.10	0.19	0.35	13.94	14.10
Excess gas	An average of 5% in addition to the ACQ sold at the contract price	$ (0.08)	-0.14	-0.26	13.61	13.49
Median pricing assuming 10% DFQ, Excess Gas, FOB, no diversion, $80 oil				1.05		14.80