Gaffney Cline

Market Advice and Estimates of Contemporary LNG Contract Prices

Report #3 June 2023

Prepared for

Australian Competition & Consumer Commission

September 2023

Gaffney Cline

Document Approval and Distribution

Copies:	Electronic (PDF)
Project No:	PY-22-2002
Prepared for:	Australian Competition & Consumer Commission

Approved by Gaffney, Cline & Associates

Project Manager: ______________________ September 2023

Nick Fulford, Global Head, Gas & LNG

Contributors: ______________________ September 2023

Prabhat Agrawal, Senior Advisor

Reviewed by: ______________________ September 2023

Andrew Duncan, Technical Director

Table of Contents

List of Figures

List of Tables

Appendices

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.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GaffneyCline has not independently verified any information provided by, or at the direction of Australian Competition & Consumer Commission and/or obtained from other sources (e.g., public domain), and has accepted the accuracy and completeness of this data. GaffneyCline has no reason to believe that any material facts have been withheld but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of data and LNG market prices and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

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 its intended purpose.

Executive Summary

As a result of the energy security concerns following the Russia-Ukraine conflict, rising consumer prices and increased costs for industry, the natural gas industry continues to be a focus of attention globally, and the topic of government level dialogue on energy policy. These features will lead to changes in anticipated oil slope price contracts in Eastern Australia, compared to the last report in this series.

The short-term sharp increase in prices during the latter part of 2022 was sudden and dramatic, coming as it did after a series of prior market disruptions arising from the COVID related demand drop, followed by supply tightness. However, prices have now returned to levels closer to the average for the last 5 years, and forward price curves suggest a continuing fall in the ratio of gas to oil prices.

The way in which the international gas industry has responded to the major challenges has played a big part in the downward price trend now seen in the market, with both increasing LNG supplies to Europe, and an unparalleled expansion in regasification capacity. Together, these factors have addressed some of the biggest energy challenges faced by those countries heavily dependent on Russian gas. This has helped increased confidence in the resilience of global gas markets, and its ability to create appropriate price signals to incentivize gas flows to regions of high demand.

On the demand side, LNG has experienced a longer-term structural shift during 2022. The Russia-Ukraine conflict has led to the curtailment of about two thirds of Russian gas imports to Europe in the latter part of 2022, and the supply shock experienced by European gas buyers for whom Russia is a major supplier has placed significant demands on the flexibility of the LNG supply chain. However, gas buyers have been able to mitigate supply shortfalls by leveraging the optionality inherent in the marine infrastructure used by the industry, which allows cargoes to move freely to high value markets anywhere in the world, subject to regasification facility availability.

In 2022 European imports of LNG grew by 45 MT (2,570 PJ), and regasification capacity is being augmented on an accelerated timeframe with over 40 MTPA (2,300 PJ) of new regasification capacity operating or under construction projected by 2025. In market terms, this increase in demand represents over a half of the Australian LNG exports in 2022, and the impact on global gas prices is commensurate with this magnitude of change.

US LNG exporters, in particular, have demonstrated a degree of agility and creativity in adjusting to this supply crisis and have been largely responsible for enabling European gas and electricity entities to withstand the crisis without major disruption. This response is likely to assist in bringing down global prices, including the oil indexed contracts that apply to customers in Australia.

Although these supply improvements are helping to align supply with demand, the jump in demand from Europe continues to create demand pressures in the short to medium term and is expected to be a permanent shift in the market, with some estimates expecting European demand to grow to about 140 MTPA (8,000 PJ) by 2030[1], equivalent to about 160% of Australia's LNG nameplate export capacity.

[1] Shell LNG Outlook, 2023

A full return to the more affordable gas prices (comparable with oil on a thermal equivalent basis) seen in the 2018 to 2021 period is unlikely, and oil indexation levels will continue to run higher than the averages seen in those years in the medium term.

While the recent supply and demand changes have been significant, viewed in historic terms, they have also served to underline global confidence in LNG as a secure and stable feature of energy supply, and may help to reduce volatility in oil index pricing levels for natural gas contracts in Australia.

With the disruption of the industry seemingly now addressed, the LNG sector is expected to continue to grow to meet demand. This growth will be partly met by the expansion that is underway in Qatar, further expansion of capacity at LNG Canada and the two projects underway in the much-delayed Mozambique development, the project underway in Senegal/Mauritania and potential LNG investment in Tanzania.

In general, the demand uncertainty up to 2030 is less significant, with the structural shift in European demand owing to the substitution of Russian pipeline imports, coupled with LNG demand for power generation in Asia, combining to create a strong foundation for increasing volumes.

The key uncertainty facing the LNG and wider gas supply industry, however, is longer-term demand levels, and the extent to which these will be affected by CO_2 emissions legal and regulatory mechanisms as the world strives to achieve a “Net Zero” outcome by 2050 or before.

Based on these expectations, some degree of price differential might be expected, with higher prices applying to natural gas supplies which can demonstrably show a lower carbon impact. This will in turn affect industrial products produced, and any carbon pricing impact that this might have.

Over the next five years, some differentiation in oil indexed pricing might be anticipated, for gas that has a verified lower carbon intensity attracting a higher oil index.

With this backdrop of a changing global gas market, this report is the third in a series intended to assist in estimating medium-term LNG prices based on an oil index, which is produced to inform the ACCC’s LNG netback price series. As set out in the ACCC scope of work, this is focused on publishing oil-linked longer-term forward LNG netback prices extending to 5 years, calculated by reference to an oil slope. The report should be read in conjunction with the previously published paper on methodology, which sets out the background and logic of the calculations and estimates adopted in this report.

In assessing the conclusions of this report, the following considerations should be borne in mind:

- While the methodology is considered robust and appropriate, it should be noted that even with oil indexation levels that are closer to the averages for the last 5 years, the disruption to global supplies has introduced a higher probability of unpredictability and volatility, making any attempt to forecast price levels much more challenging than it would be in more routine market conditions.
- The methodology report highlights many of the features that contribute to uncertainty and the level of confidence users of the netback series reports need to be aware of and apply, but the reader also needs to consider some of the current market events.

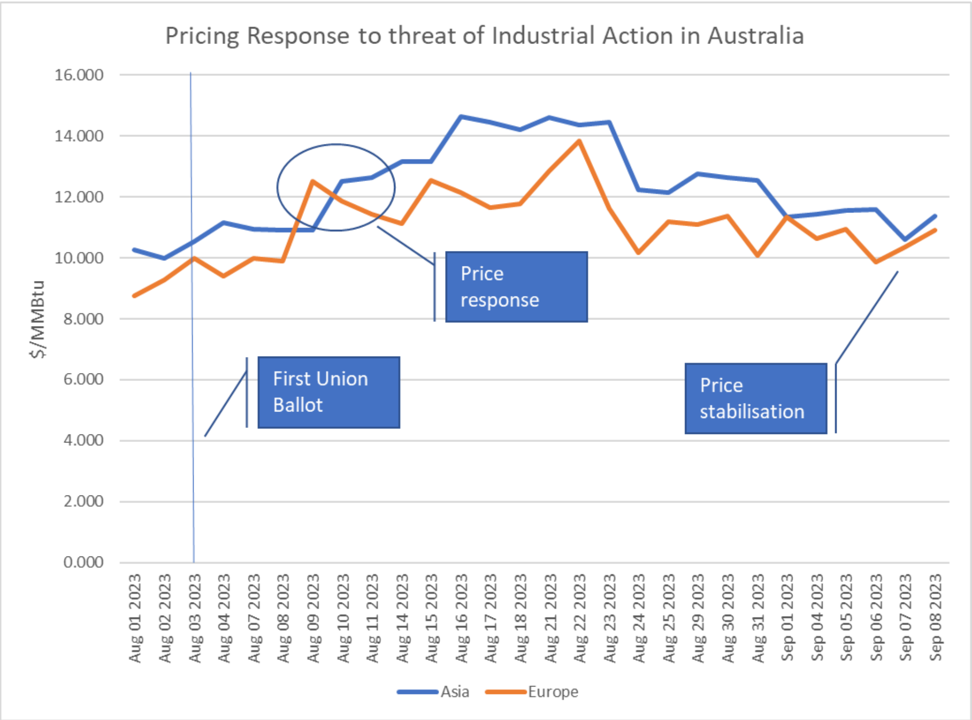
- With some supply risk still present in Europe, as we enter the northern hemisphere heating season in October 2023, some degree of market instability could return.
- The return of price sensitive customers, such as South Asian gas buyers, into the LNG market, could introduce upward pressure on oil-indexed gas prices in Australia.
- The supply risks endured during the 2022-2023 period have encouraged some buyers to increase the portion of their supply portfolio under long-term contract, which may slightly decrease volatility for Australia customers because of lower susceptibility to spot prices.
- Finally, a number of price controls and subsidies continue to apply in some markets, especially in Europe, and the implications of these have yet to be properly quantified.

For this report, therefore, gas buyers should place additional emphasis on an understanding of the wider trends in the global gas markets, to be considered alongside the calculations of the oil slope set out further in the report.

Notwithstanding the exceptional features above, the methodology developed by GaffneyCline (see box 1 below) sets out an estimated oil slope for medium-term LNG contracts for Asia delivery of 14.3%. This represents a decrease of 0.8% (a proportional reduction of 5.3%) in the anticipated medium price of natural gas, compared to December 2022.

Of particular note in recent weeks for Australian gas markets is the ongoing industrial action affecting the Gorgon and Wheatstone projects, which emerged after a union ballot on 3 August 2023. Some concerns were evident in global gas markets, which reacted on 9 August with a sharp upward move in wholesale gas prices in Europe and Asia. At the time of publication in early September, prices appeared to have stabilised and the business continuity plans published in response to the potential industrial action had reassured buyers to some extent.

Figure 1: Pricing Response to Threat of Industrial Action (US$/MMBtu), 2023



Box 1: Methodology to Estimate Medium-term LNG Contract Prices[2]

GaffneyCline estimates the oil slopes for medium-term LNG contracts using prices observed under medium-term LNG contracts entered over the previous 12 months. If there is sufficient data 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.

If there is insufficient data on medium-term contracts, 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. Short-term international tenders
2. Long run cost of US LNG Exports
3. Long-term contract signings

The relationship between these three sources 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.

Recognising these dynamics, in the event that the alternative data sources are used to complement data on medium-term LNG contracts, they will be weighted differently depending on the observed volatility in key oil and gas price indices over the previous 12 months:

- Where oil and gas indices have experienced high volatility and have been **less than 40%** correlated, more weight will be given to longer-term deals
- Where oil and gas indices have experienced average volatility and have been **more than 40% and less than 60%** correlated, equal weight will be given to the three measures
- Where oil and gas indices have experienced low volatility and have been **more than 60%** correlated, more weight will be given to shorter-term deals.

These three parameters will be combined to produce a single slope data point with medium-term LNG contract slope data using a simple arithmetic average to generate the final six-monthly oil slope estimates. See Appendix III for a detailed explanation of the methodology.

[2] See the ACCC website for a full explanation of GaffneyCline's methodology https://www.accc.gov.au/system/files/GaffneyCline%20methodology%20discussion%20paper%20LNG%20price%20estimates.pdf

The starting point for the estimated oil slope is the analysis of medium-term contracts. However, we have observed that no medium-term oil-indexed contracts have been entered into within the last 12 months, for which data is available from the usual subscription price reporting services.

We, therefore, move to a secondary analysis, taking a combination (that depends on the degree of market volatility) of international tenders, US LRMC and long-term SPAs. Based on the methodology set out, in a volatile market such as the one that exists today, we place a weighting on the various input parameters in the proportion of 1:2:3.

- Least weighting on international tenders (on the basis that they reflect short-term market pressures)
- Medium weighting on US LRMC
- Most weighting on Long Term SPAs

Applying the process to the data and calculations above, the following oil slope estimation is calculated (without reference to the non-conforming but illustrative data points from the assessment of medium-term contracts).

Contract Type	Weights	Slope	Section
Volume-weighted international tenders	1	18.0%	3.2
LRMC US exports converted to slope	2	13.6%	3.3
Volume weighted long-term deals*	3	13.6%	3.4
Published Slope Estimate		**14.3%**	
*Long-term slope of 12.9% is adjusted +5% for financing benefits			

Note that these estimates are sensitive to assumptions about market volatility and the corresponding weighting (as explained in Box 1 and **Appendix III**). For example, a greater weight for international tenders would result in a higher average slope.

Note regarding current unprecedented volatility in global gas markets

Although prices are returning to closer to median levels of last five years, recent volatility in global gas market prices mean that historical measures of oil and gas correlation, price volatility and other fundamental features of the oil slope derivation in this report have less applicability than in the pre-2020 period. The last five-year average is a lot higher than the median due to the very high positive skewed markets in 2021-2022.

Prices US$/MMBtu	East Asia +1month	North Europe +1month	ICIS Brent +1month	Henry Hub +1month
5-year Average	14.6	13.2	12.2	3.6
5-year Median	10.0	7.5	12.2	2.8
31-May-2023	9.5	8.3	13.1	2.3

In spite the downward trend of recent months, there is a risk of supply disruption towards the end of this year, which could place upward pressures on pricing compared to the analysis set out in the report.

As a result, shorter-term gas sale and purchase agreements could carry a significant premium in terms of historic oil indexation levels, medium-term contracts less so, and long-term contracts (more than 10 years) will be least affected. The flexibility of the methodology referenced in this report, therefore, serves to cater for adapting market conditions and allows for a changing weighting in the parameters that influence the estimations.

In parallel to the analytical approach to price forecasting set out, general market sentiment garnered from confidential market sources helps to provide additional context. This suggests that an oil slope in the region of 15-17% or more is likely to apply to LNG delivered in the shorter term, where unmet European demand continues to have an effect. In the longer term, futures market curves suggest that oil and gas prices will return to a relationship reflected by the thermal energy contained in the fuel adjusted for regas costs, potentially in the region of 12-14%.

We believe these market indicators are consistent with the analysis and recommendations in this report, which have arrived at a 14.3% slope estimate, but buyers in Eastern Australia may find that gas suppliers are seeking a higher level of price in the short term, particularly in the next 12 to 24 months.

Discussion

1 Overview of LNG Market Developments

1.1 European Supply Disruption

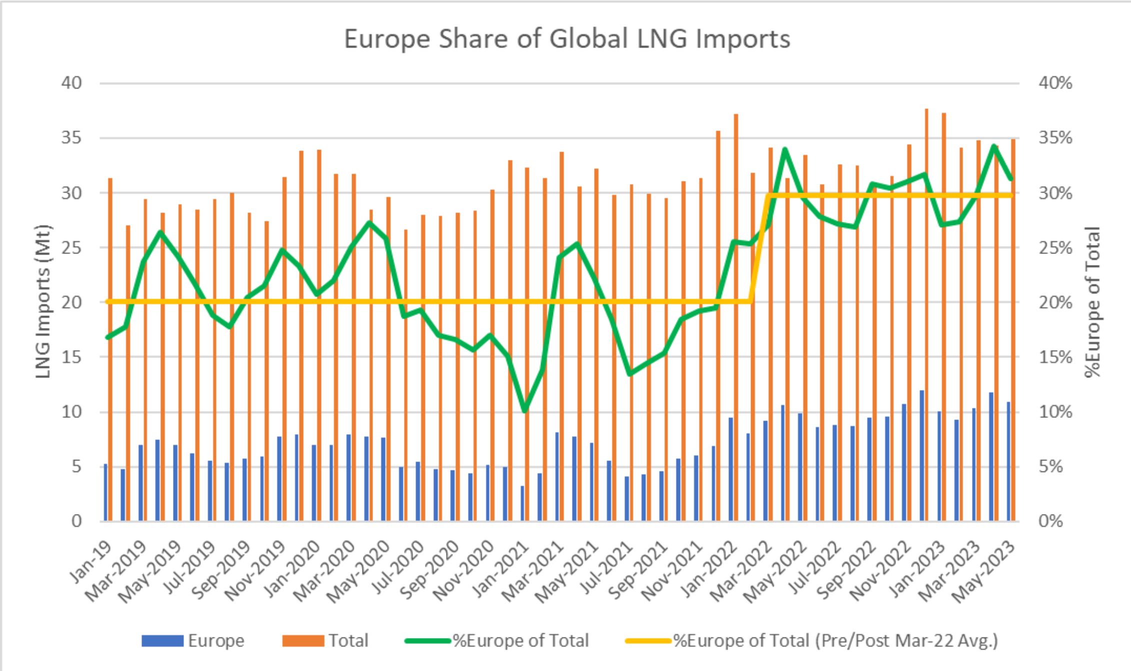
The medium to long term effects of the disruption to European gas supplies created by the Russia-Ukraine conflict appears to have resulted in a structural shift in LNG flows. This is evidenced by the continuing increase in LNG market share accounted for by European buyers, and no apparent change in the shortfall in Russian gas imports to Europe. Pre-conflict Russian gas exports averaged 232 Million Cubic Meter per Day (MCM per Day) and within six months Europe reduced reliance on Russian gas by almost 80% to recent average of 50 MCM per Day as shown in **Figure 2** below.

Figure 2: Russian Exports to Europe

Source: IEA, GaffneyCline Analysis

As can be seen in **Figure 3** below, the European share of US LNG exports rose from about 20% pre-conflict to nearer 30% afterwards. In order to better accommodate this increase in LNG demand, additional LNG regasification infrastructure, particularly the use of FSRU's, is planned to increase substantially. One of the planned German FSRUs was commissioned in January (Wilhelmshaven) after a 10-month work program, with a second added shortly afterwards at Lubmin on the Baltic Sea. The speed with which these floating facilities were conceived and executed has alleviated some of the medium-term concerns over European supplies, though when the heating season recommences in October of 2023 gas buyers will be looking carefully at the supply situation once again.

Figure 3: Increasing Share of US LNG Exports Delivered to Europe

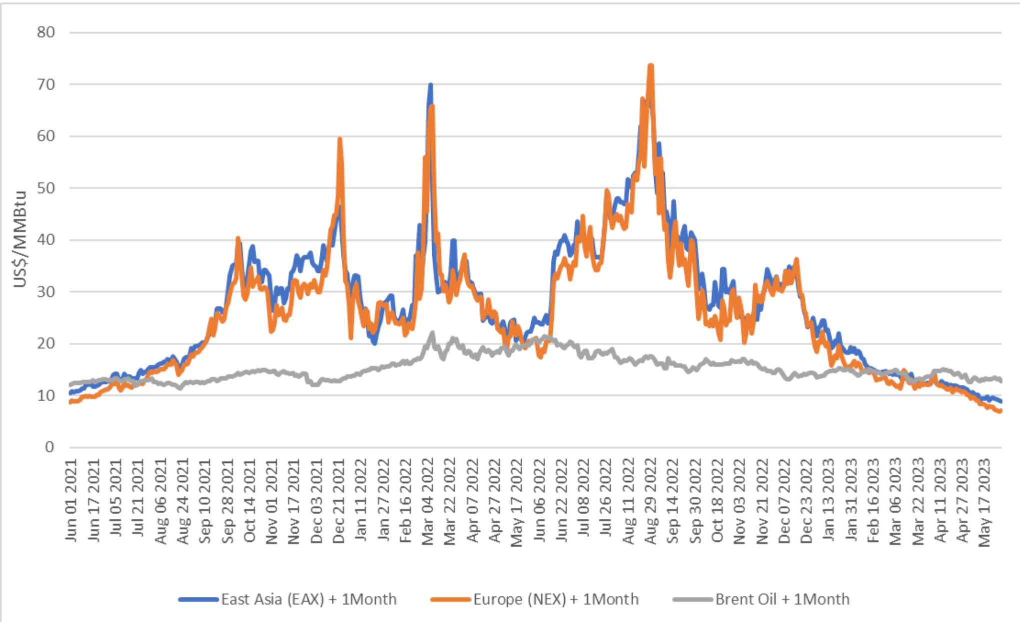


Source: ICIS, GaffneyCline Analysis

1.2 Impact on Wholesale Natural Gas Markets

The price shocks that characterised late summer and the start of winter 2022 have dissipated in recent months, with both demand falling (with the European summer months) and supply availability easing (**Figure 4**).

Figure 4: East Asian and European Gas Prices in Last Two Years



Source: ICIS, GaffneyCline analysis

By May 2023 the wholesale price of natural gas in Continental Europe, measured by reference to the TTF hub had reduced to about US$8/MMBtu compared to levels of over US$90/MMBtu in August 2022 which in oil terms was equivalent to approximately US$540/bbl. Asian prices have also returned to a more typical premium to European prices, representative of the difference in freight costs and origin of the LNG.

1.3 Economic Effects and Price Regulation

In June 2023, the EU took a decision to suspend the electricity price subsidies that had been introduced as an emergency measure following the sharp rise in residential and commercial energy prices. Germany, however, is set to continue some price subsidies in the medium term in response to industry concerns, and reductions in peak electricity consumption were also extended as part of wider measures to prevent price spikes affecting consumer prices.

In March 2023 the EU announced that although supply concerns had eased, a voluntary 15% reduction in gas consumption would continue until March 2024, when arrangements would be reviewed.

In Britain, an emergency fuel subsidy mechanism was continued to March 2024, but most observers consider it unlikely to be triggered given the fall in wholesale gas prices and the relatively stable pricing in recent months.

1.4 Price Arbitrage and Short-Term Trading

With financial results from 2022 now being made public, it is clear that LNG trading activities during that year resulted in some exceptionally high earnings, albeit with a considerable strain placed on balance sheets and credit. In some cases, these trading activities are an integral part of the businesses associated with LNG supply, but in others these are pure trading profits, often combined with other traded commodities. These very high trading profits will have added to the cost base of LNG and gas consumers during the year, which will have in effect contributed to higher oil price slope levels, and the more typical trading conditions that exist in June 2023 will mitigate this effect and put downward pressure on oil slope indices experienced by gas buyers.

1.5 Oil Price Stability and Impact on Pricing Trends

During this period of wholesale gas price instability, oil prices have remained very stable, relatively speaking, and this has set up a pricing dynamic which is driving gas sale and purchase decisions.

For end-users or industrial consumers, oil indexation therefore represents a lower risk strategy which can be better managed in the context of industrial product pricing and the cost of goods sold. The challenges of managing wholesale gas price risk are much greater than previously and typically not feasible for businesses who do not specialise in commodity price risk management. Although the trend in the pre-2020 gas market had been for increasing numbers of supply contracts to be priced using wholesale gas indices, with less emphasis on oil indexation, this trend may halt or reverse.

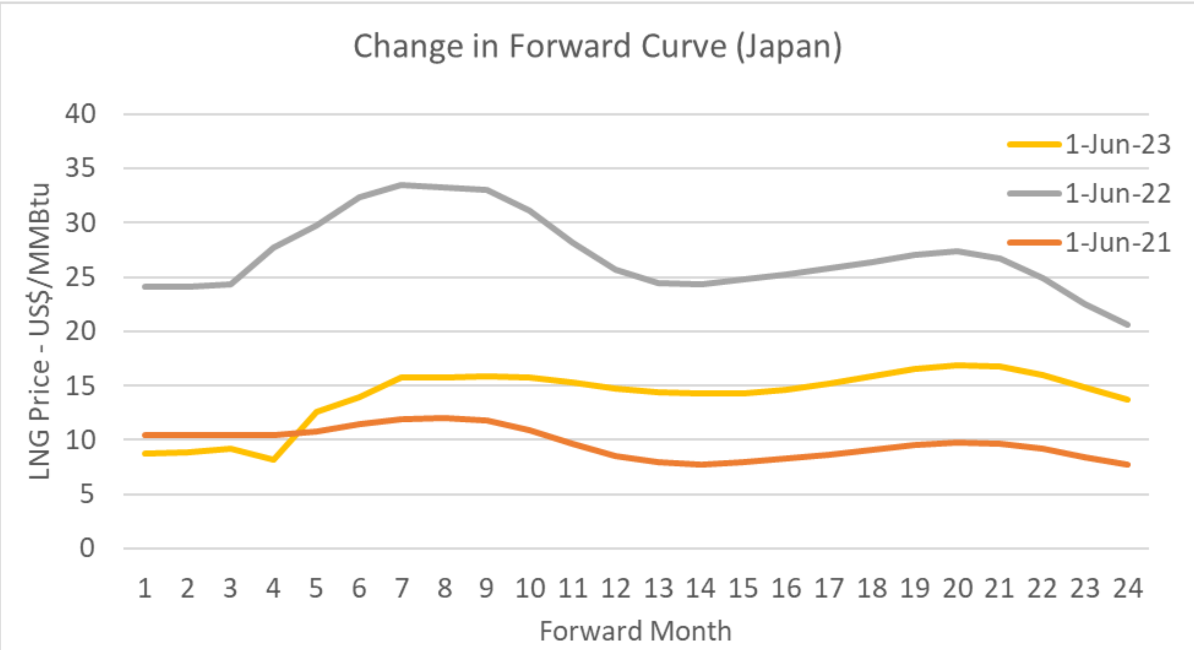
As such, while these wider features affecting wholesale gas indices are important to understand, the methodology set out for this LNG netback series continues to be relevant and helpful in arriving at an expected oil-indexed price range applicable over the next several years.

1.6 Forward Market Outlook

As we reach the middle of 2023, it appears that the easing in forward gas prices evident in the market outlook for January (that was set out in our last but one report in this series) have been shown to be a good guide to realised prices in the last 6 months. Gas and LNG prices appear to have fallen back to more typical levels, though still within the higher bound, and forward market prices indicate a gradual return to a more typical pattern over the next two winter seasons. While the shortfall in Russian gas imports to Europe continues to create upward pressure, the emergency actions by EU and others appear to have alleviated very high prices seen of the last few months. Furthermore, additional LNG supplies from the US Gulf Coast, as well as other projects under development such as Mozambique, Senegal and, in the longer term, export projects such as Tanzania all suggest that substitute supplies can be brought on stream.

Figure 5 below indicates that while the second half of 2022 was characterised by record prices, the forward curve which reflects where future deliveries of LNG are being transacted, has fallen back to levels closer to the pre-crisis curve from June 2021, and has dropped significantly since the outlook 12 months ago in June 2022.

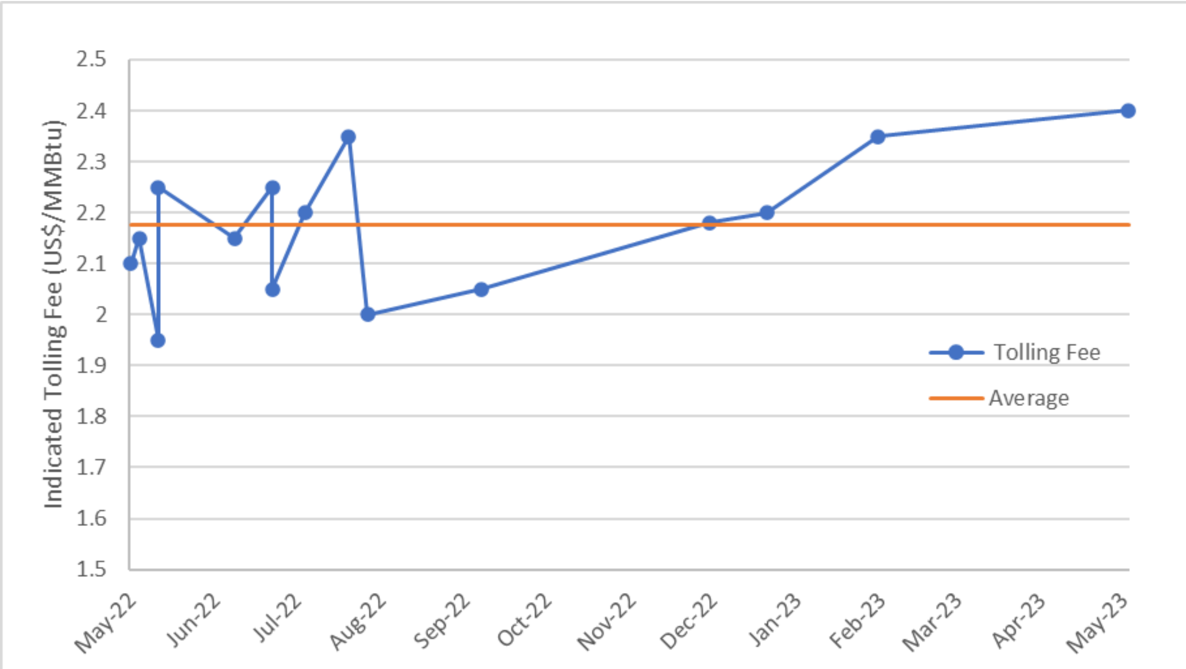
Figure 5: Change in Gas Forward Price for Japan Delivery



Source: ICIS, GaffneyCline analysis

There is continuing evidence that the high prices in price sensitive importing countries such as India and Pakistan have caused a suspension in LNG sale and purchase negotiations. For example, the amount of LNG that India imported for the period April 2022 to March 2023 was down over 14% on previous years, but with recent decreases in prices imported volumes have recovered somewhat with a year-on-year increase of over 6% in April 2023. East Asian LNG Prices (EAX+1Month) averaged US$30.3/MMBtu from April 2022 to March 2023 and decreased to US$12.2/MMBtu in April 2023. Another outcome of the price volatility of recent months appears to be a move away from spot purchases, where Petronet CEO recently indicated that they would focus their efforts on term trades. This is evidenced in, several long-term deals (15-20 years) have been signed in the last few months with US suppliers, predominantly by Chinese LNG importers. This appears to confirm the trend away from relying on spot deals, where the price volatility of the last few months has led to costly LNG import bills. These long-term deals have been reported to include tolling rates in the US$2.00/MMBtu to US$2.40/MMBtu range. However, growing demand for LNG, especially for projects that can deliver in the 2025/6 timeframe, and increasing concerns over inflation impacting construction costs suggests that there is upward pressure on this number. For these reasons, we are once again increasing our tolling cost assumption from US$2.10/MMBtu to US$2.20/MMBtu (an increase of 5%) when assessing the long-term pricing estimates for US exports.

Figure 6: Indicated Tolling Fee (US$/MMBtu) - USA Henry Hub Link LNG Export

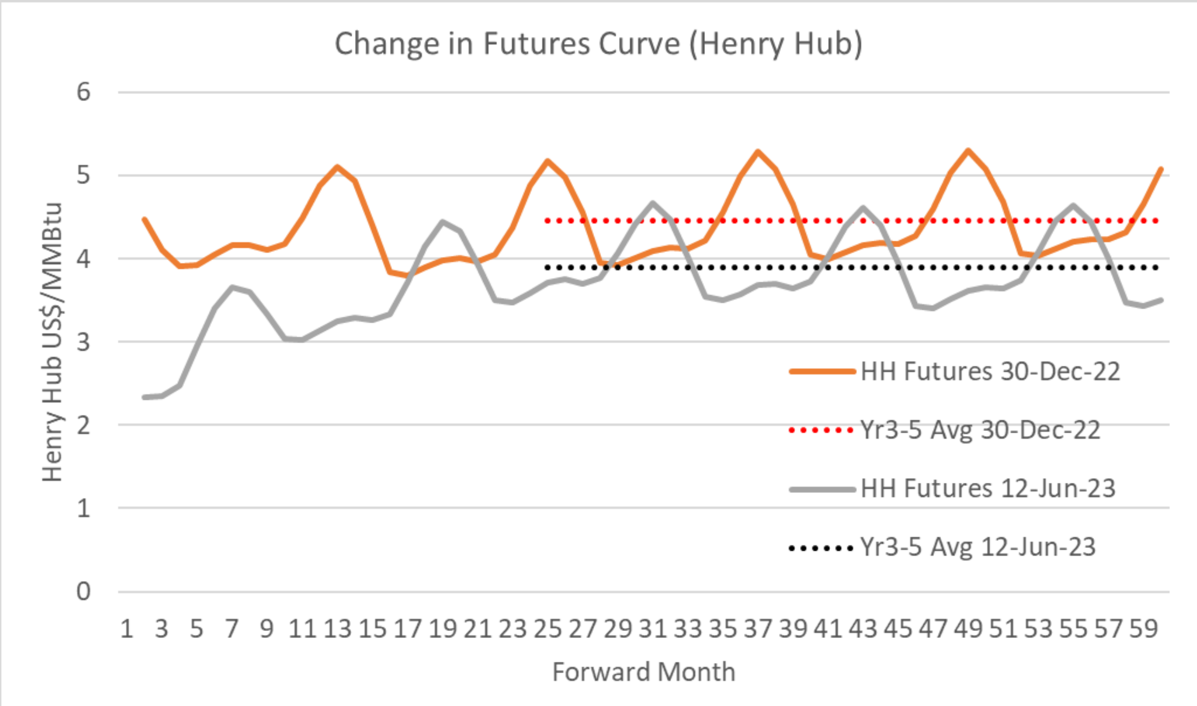


Source: ICIS, GaffneyCline analysis

Henry Hub prices in the US have continued to show much greater stability than wholesale market prices elsewhere with a trend in the futures curve to just over US$3.75/MMBtu for January 2024. The price reflects an anticipated continued demand for feed gas for LNG exports in the coming years. Translated into oil slope levels, this would place January 2024 oil indices, on a delivered to Asia basis, at around 10.8%, based on the January 2024 Brent futures price of US$81/barrel[3].

[3] $3.75/MMBtu Henry Hub with 15% allowance for fuel and basis comes to $4.3125, then adding $2.20/MMBtu as our current estimate of tolling fee and $2.21 current freight estimate to Asia comes to a total of $8.7225/MMBtu delivered, which divided by the January 24 forward oil price of $81/barrel comes to an imputed oil index of 10.769%

Figure 7: Change in HH Forward Curve



Based on average front month Brent price and front month Spot North Asian LNG prices over the past three months (Mar 2023 to May 2023), the slope would sit at 13.4%. For the same contracts the slope was as high as 30.5% based on average prices over Q4 2023. This is an indication of how quickly spot LNG markets have decreased since publication of previous report.

1.7 Pricing Trends / Market Sentiment

Although pricing information is notoriously hard to derive in the LNG sector, market indicators seen by the Gas and LNG team at GaffneyCline suggest that medium-term LNG deals of around 10 years are most affected by the recent disruptions and are typically being offered within the range of 16-17% Brent Crude in the case of contract renewals with LNG deliveries commencing in the short term. For LNG deliveries starting in the medium term, say 2024-2026, buyer and seller expectations appear to be lower, with a range of 12.5% to 14% being considered appropriate.

Furthermore, while FOB prices in the low to mid 10% range were seen prior to 2022 for LNG projects seeking AAA credit rated long-term offtakers, prices in this range no longer appear achievable, other than potentially for LNG projects that have not reached FID and do not yet have market credibility.

However, pricing trends continue to be influenced by broader market fundamentals outside the recent disruption, which have also changed considerably in recent years.

The LNG sector underwent a period of economic strain in the 2020 timeframe owing to COVID related demand reductions which coincided with a structural oversupply in the global LNG market. This caused spot prices to fall to unprecedented low levels, and some liquefaction plants were shut down owing to the cash losses that would have resulted from continued export. Subsequently, faster than anticipated demand recovery and growth, especially in Asia, and delays in new plant construction and FID (e.g. including but not limited to Mozambique, and some US projects which have since picked up the pace again) coupled with unplanned outages at LNG facilities (e.g. including but not limited to Hammerfest in Norway, Prelude, and for a brief period US Gulf Coast facility disruptions due to weather) saw a gradual increase in price to the point where supply shortages became apparent by winter of 2021/22.

During 2022, LNG imports reached 399.4 Million Tonnes (MT), a 5.6% increase over 2021, majority of growth coming from Europe with 71% increase to almost 116 MT to replace lower Russian pipeline gas. Additional European LNG demand and the resulting rise in global LNG prices contributed to a major reduction in demand from Asia (especially China and South Asia) and the Americas. Chinese LNG demand fell by 21% to 63.6 MT due to additional pipeline gas supplies and reduction in demand due to slower economic activity and the impact of the strictly applied COVID lockdowns. Most of the spot market imports were taken by Europe.

Preliminary analysis based on shipping movements suggests that in 2022, Australia, the US and Qatar all exported about 81 MT of LNG each. The US would have been the bigger exporter but lost its lead due to a major outage in Freeport LNG facility in USA.

Since the last report was published in January, significant additional LNG export capacity has been sanctioned from US terminals. Cheniere has approved a 10 MTPA addition to its Corpus Christi LNG terminal, and Venture Global approved the second of three terminals in its portfolio, the 20 MTPA Plaquemines facility in Louisiana. Other LNG terminals are approaching FID, including the Energy Transfer project at Lake Charles, which will bring an additional 16.5 MTPA into the market. During 2023 other projects will be vying for FID, many of which are rapidly securing offtake. These include a floating LNG terminal, with an initial capacity of 3.5 MTPA, and another Venture Global terminal which is currently seeking firm offtake.

Turning to the Pacific basin, interest in the Alaska LNG export project (approx. 24 MTPA) appears to have revived, especially given Asian buyer concerns over the proportion of Gulf Coast LNG being taken to Europe.

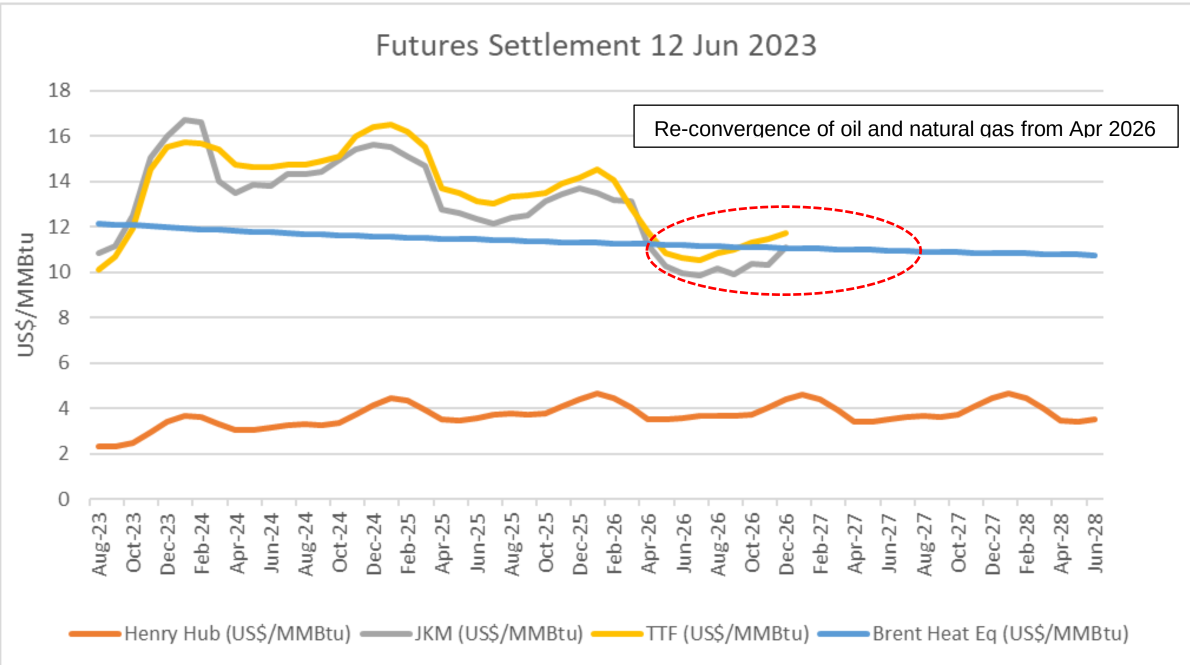
However, with the market oversupply of the 2018-2020 still relatively fresh in the minds of LNG developers and lenders, it is likely that many US and other LNG export projects currently under consideration may not finally come to market. An indication of the continuing challenges to achieving FID for US export projects was the cancellation by Shell and Vitol of their conditional offtake contracts from the Driftwood LNG project in September 2022, at the height of the European gas market disruption. The project now looks less likely to proceed, and the focus is on projects that can come to market prior the 2025/6 timeframe when LNG supply pressures are anticipated to ease.

Re-exports remain a relatively low proportion of trades, mainly owing to the recent pricing volatility which can reverse pricing differentials in less than the time a vessel can respond. Floating LNG storage, using “slow steaming” or other techniques to keep LNG on the high seas and profit from price changes has also seen an uptick in the last 6 months.

As discussed in the previous report, since 2020, the relationship between the price of natural gas and oil had become increasingly uncorrelated, as each commodity has responded to its own market conditions. With fuel switching offering operational and economic challenges, the structural separation of the oil and natural gas markets continues to lessen the linkages between the two. However, the trend back towards longer-term contracts and the relative stability of oil prices compared to natural gas are conspiring to sustain interest in oil indexed contracts, especially for end users.

The graph below indicates that the futures market is anticipating a gradual convergence of oil and wholesale gas prices, anticipated after the April 2026 timeframe. This realignment may however pause or reverse if future supply disruption in Europe occurs. Spot prices should ease with additional LNG supplies coming onstream in 2026/27. Futures settlements for JKM and TTF beyond Dec-2026 are not shown as there is no open interest beyond these dates.

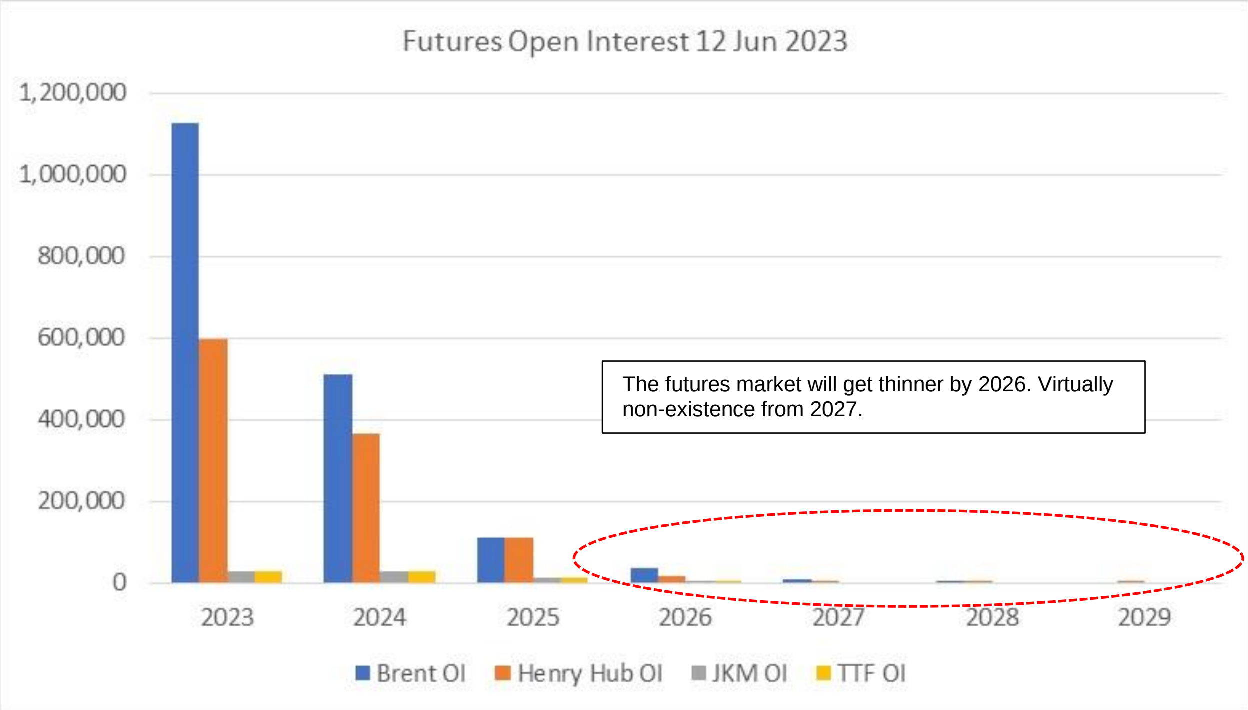
Figure 8: Futures Market Price Curves



Source: ICE, CME and GaffneyCline Analysis

JKM and TTF futures prices are gradually converging to oil equivalent prices in 2026 in a very thin market. Thus, the reliability of JKM, as well as TTF futures from 2025, is limited as a market indicator, further reinforcing the potential use of oil indexation for end users not equipped to manage gas price volatility.

Figure 9: Open Interest for Oil and Gas Futures Markets



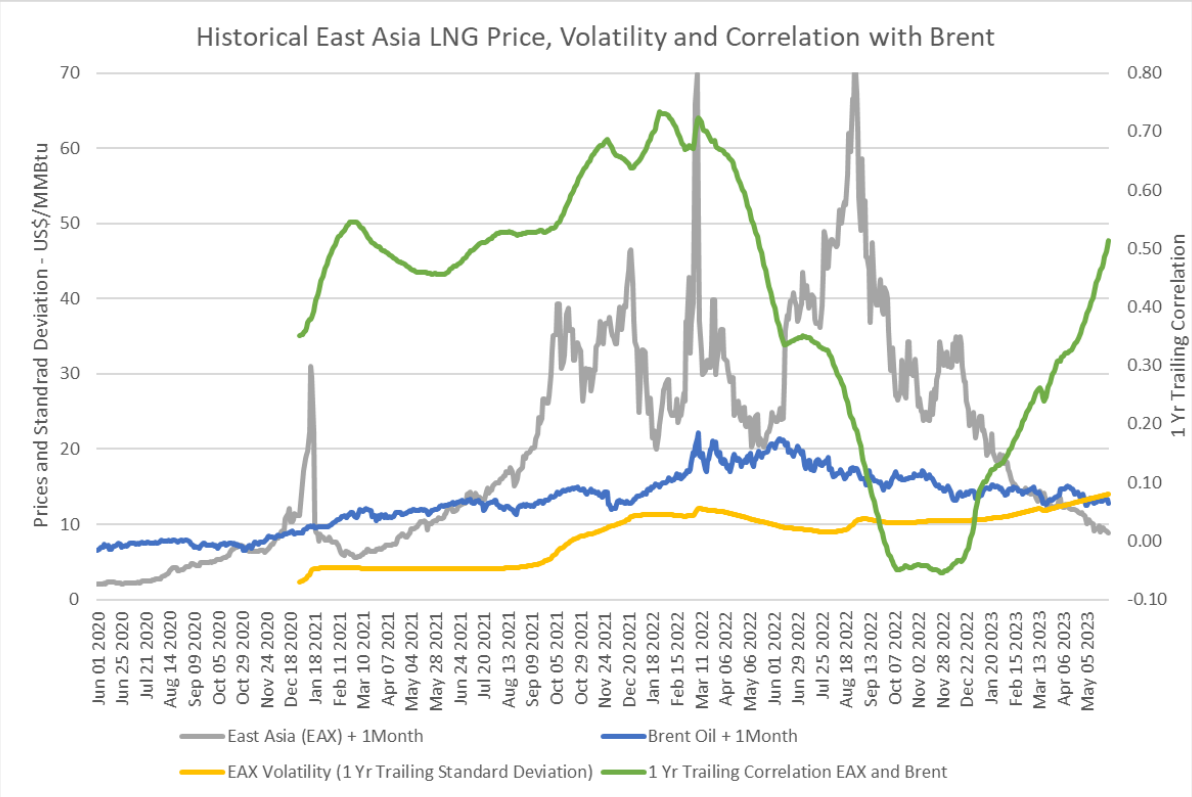
Source: ICE, CME and GaffneyCline Analysis

The analysis set out below provides some additional insights that help those wishing to more deeply assess the relationships between oil pricing and indexation versus wholesale gas indices.

The last three-year data for east Asian LNG prices (EAX[4]), volatility and correlation with Brent crude oil prices are shown in the next chart.

[4] The EAX is published by ICIS Heren and is calculated by averaging each day's DES front-month and second-month ahead assessments for Japan, South Korea, Taiwan, and China. GaffneyCline consider this to be a good proxy for Platts JKM pricing.

Figure 10: Natural Gas Price Correlation and Volatility



Source: ICIS and GaffneyCline Analysis

Figure 10 above demonstrates the very unstable correlation between spot LNG prices and Brent over the last 24 months. This market feature may cause some buyers to place a risk premium on index-priced gas, compared to Brent. This would have the effect of depressing oil slopes slightly, compared to gas supplied under identical terms, but priced against an index such as JKM, and may also encourage some buyers towards oil-indexation while the global supply and demand balance continues to equilibrate. However, the effect of a tight market on gas prices generally is a bigger influence on prices and slope, which is why we are seeing oil slopes much higher than in previous years.

1.8 Impact of Carbon Intensity on Natural Gas Pricing

Increasing attention is being given to the likely impact on natural gas demand and pricing paradigms created by the shift towards lower carbon forms of energy.

In the US and Europe, there are growing examples of carbon differentiated natural gas pricing. While price levels are primarily based on fundamental supply and demand considerations, price differences are also being seen based on the carbon intensity of the natural gas or LNG that is being sold.

For example, in the US, proponents of "Certified Gas" a standard for gas that uses less energy and less water to produce, are striving to achieve a 5% price premium. In May 2023, a number of senior natural gas executives also cited moves to premium pricing of low emissions natural gas.[5]

This is an evolving pricing feature for natural gas and an exact premium for certified or verified sources of low emissions or responsibly sourced natural gas is not yet fully defined. As an example, however, if a premium of 5% were to apply, and an individual buyer wished to purchase from a verified source of low emissions natural gas, this would increase our oil-indexation factor from 14.3% to around 15%.

It should be emphasised that this feature of natural gas pricing is not well established, and furthermore it depends on the unique features governing the decision making of a particular buyer and seller of gas.

1.9 Summary of LNG Pricing Data within the Previous 12 Months

1.9.1 Medium-Term Oil Indexed Contracts

No Medium-Term Oil[6] Indexed Contracts have been entered into that are on public record or in the ICIS database within the last 12 months.

However, there are some market insights that are of interest for medium-term oil linked LNG contracts reported:

- Pertamina sold ten cargos at a Brent Slope of around 23% FOB East Kalimantan. Two cargos in 2024, four in 2025 and four in 2026 were offered and deal was closed in September 2022.
- Chinese buyers received limited offers covering 2023-2025 or 2024-2026 delivery with Brent oil linked slopes varying from 17% to 20% in September 2022.
- Japan's Chugoku Electic awarded a two tranche buy tender in March 2023, for 2023-2025 and 2026-2030 delivery, to a Japanese trader and British oil major. 2023 to 2025 tranche is reported to be priced between 20% to 23% to Brent. 2026 to 2030 tranche was awarded around 13% to 14%.

[5] https://www.energyintel.com/00000186-ccc6-d54f-abf7-eec647c50000

[6] For this analysis, a medium-term oil indexed contract is an SPA of less than 7 years duration, with a full or partial oil slope component of the price, for which reliable pricing information is in the public domain or can be derived from the subscription service operated by ICIS

- Japan's Tohoku awarded a term tender to BP and Vitol for cargoes to be delivered between 2023 and 2026 at a slope of 17% to 18% to crude oil in April 2023.
- Pertamina signed two LNG supply deals for 2024 to 2026 delivery from Bontang, whose highest bids were around 23% and 17% slope to Brent respectively in June 2023. Tender for 36 cargos by Indian oil for delivery in India between 2023 to 2026 was partially closed at 15% plus Brent slope in June 2023.

1.9.2 Long-Term Oil Indexed Contracts in the Last 12 Months

A total of 55 long-term LNG deals were agreed upon during the last 12 months (Jun 2022 to May 2023), which compares with 54 in 12 months period a year earlier. Of these signed in last 12 months, 35 were signed with existing or prospective US sellers. **Table 1** below shows the long-term deals signed according to country of origin. Most of these SPAs and the associated contracted volume originated from the United States, followed by Qatar, with a much smaller number.

Table 1: Recent Long-term Sale and Purchase Agreements (by origin)

Origin	Jun 2022 to May 2023		Jun 2021 to May 2022	
	# of Contracts	Contracted Volume (MT)	# of Contracts	Contracted Volume (MT)
United States	35	880	28	658
Qatar	2	138	6	148
Mexico	4	74	1	40
Oman	8	57	-	-
Others	3	18	5	43
Undeclared	3	20	14	148
Total	**55**	**1,187**	**54**	**1,038**

As shown in **Table 2** below, most of the contracts' destination is China. Many contracts did not have declared destinations, but their LNG mostly originated from the United States. This could be due to buyers maintaining flexibility to divert cargo for the best pricing. Germany emerged as second biggest contract destination after signing four long-terms contracts, three from USA and one from Qatar. This is the first time that a long-term contract with Germany as a destination is reported in the ICIS database dating back to 1972.

Table 2: Recent long-term Sale and Purchase Agreements (by destination)

Destination	Jun 2022 to May 2023		Jun 2021 to May 2022	
	# of Contracts	Contracted Volume (MT)	# of Contracts	Contracted Volume (MT)
China	5	116	27	515
Germany	4	64	-	-
Japan	3	55	-	-
South Korea	2	8	3	59
Others	3	50	8	157
Undeclared	38	895	16	308
Total	**55**	**1,187**	**54**	**1,038**

The bulk of the contracts signed are indexed to Henry Hub. Only two contracts were reported to have been agreed upon based on an oil slope. A large share of Henry Hub pricing is due to the bulk of SPA's signed are from existing and upcoming LNG projects in USA.

Table 3: Recent Long-term Sale and Purchase Agreements (by pricing mechanism)

Contract Type	# of Contracts	Contracted Volume (MT)
Henry Hub	31	759
Brent	2	128
Asia Spot Price	1	30
Undeclared	21	270
Total	**55**	**1,187**

1.9.3 International Tenders

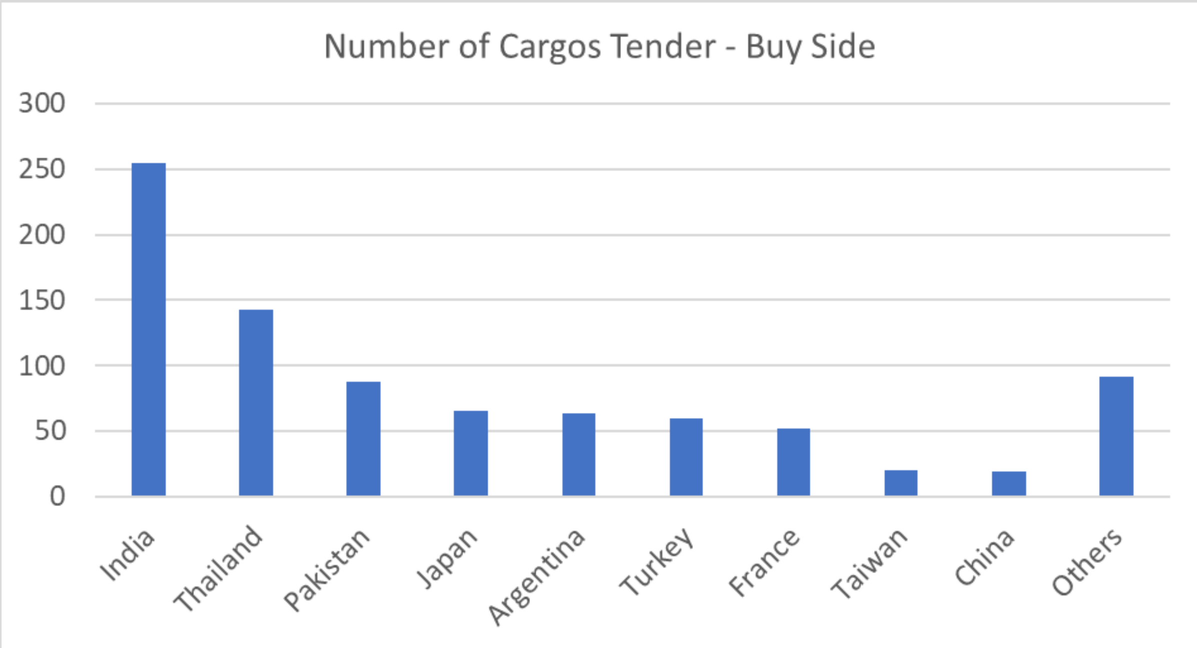
In the last 12 months (June 2022 to May 2023), a total of 418 international tenders were issued of which 221 were on the buy side and 197 were on the sell side.

63% of these tenders were for a single cargo, and 24% involved more than 1 and less than 5 cargoes. Only 13% of tenders were for 5 or more cargoes.

In terms of the number of cargos tendered, India is a dominant player on the buy side and accounted for 255 out of a total of 856 (approximately 30%) of the buy side cargos tendered. Thailand and Pakistan are other major buyers using tenders. On the sell side a total 321 cargos were tendered with main active players from Egypt, Australia and USA.

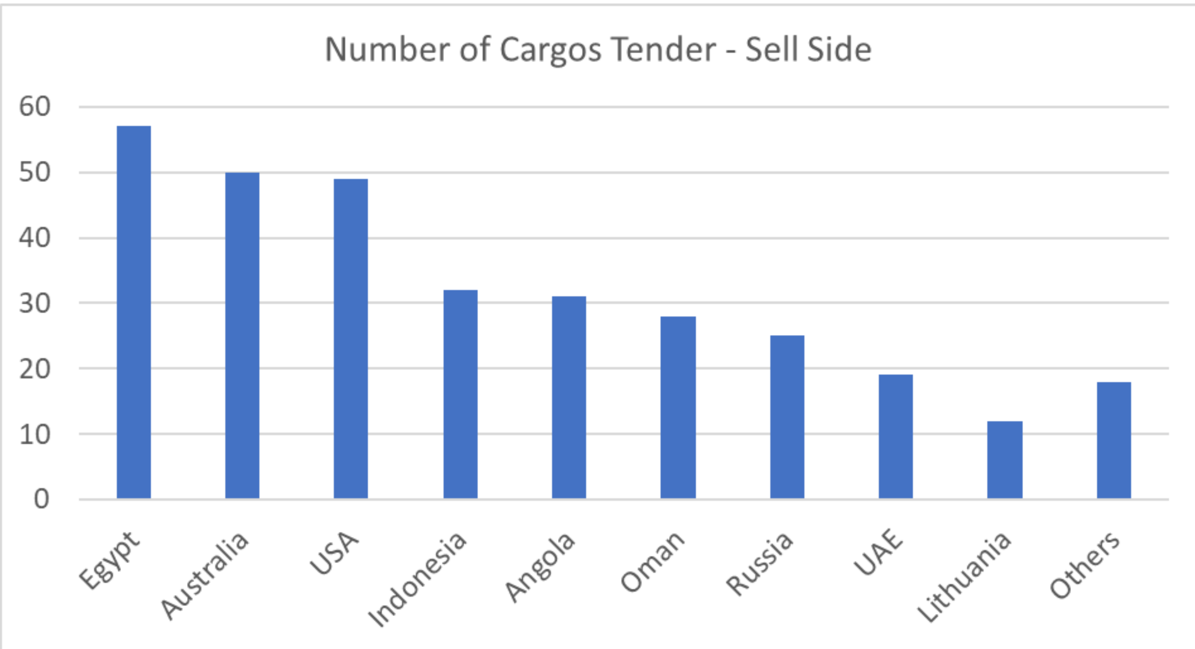
Figure 11 shows that the international tender data can be used as a good reference for Asia deliveries which will have most influence on market conditions in Australia (after applying the netback to Australia using ACCC methodology). Seven of the top 10 players in the international tender markets are Asian buyers, while European buyers typically rely on other market mechanisms and are largely absent.

Figure 11: Buy Side Cargos Tender by Country (12 months ending 31 May 2023)



Equally, as illustrated in **Figure 12**, Australia is very well represented on the sell side, though not as predominantly as was the case in June 2022. However, we would still anticipate a reasonable link between short-term tender pricing data used in the methodology, and the pricing environment relevant to gas buyers in Eastern Australia.

Figure 12:Sell Side Cargos Tender by Country (12 months ending 31 May 2023)



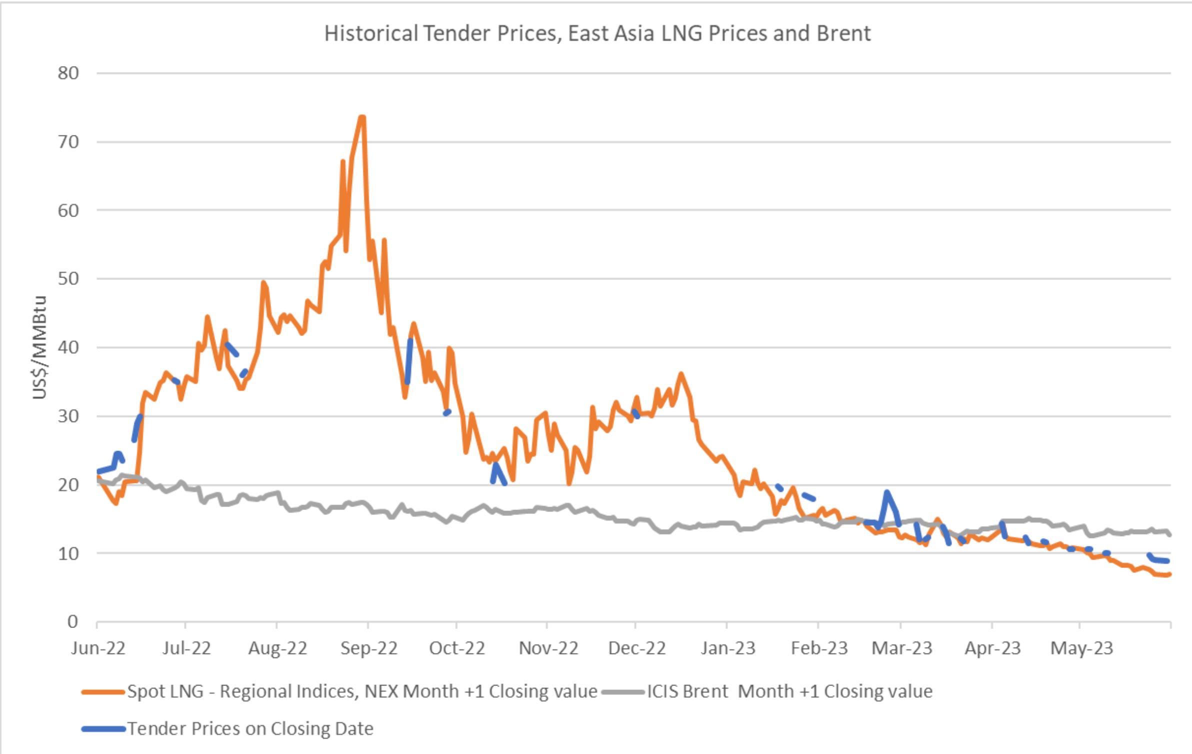
In terms of contract pricing, limited information is available. Based on available information most of the cargos were tendered at a fixed price. NE Asian marker and TTF linked tenders were second and third preferred choices.

Table 4: Recent Tenders by Pricing Mechanism (12 months to 31 May 2023)

Contract Pricing Type	Buy Side	Sell Side	Total
Fixed Price	259	55	**314**
NE Marker	94	36	**130**
TTF linked	32	19	**51**
Slope	20	0	**20**
Unknown	451	211	**662**
Total	**856**	**321**	**1,177**

In terms of pricing, available tender prices closely follow East Asian spot LNG indices. This is not surprising as tenders cater for the short-term markets. During extreme spot price movements, tender price information is sparsely available.

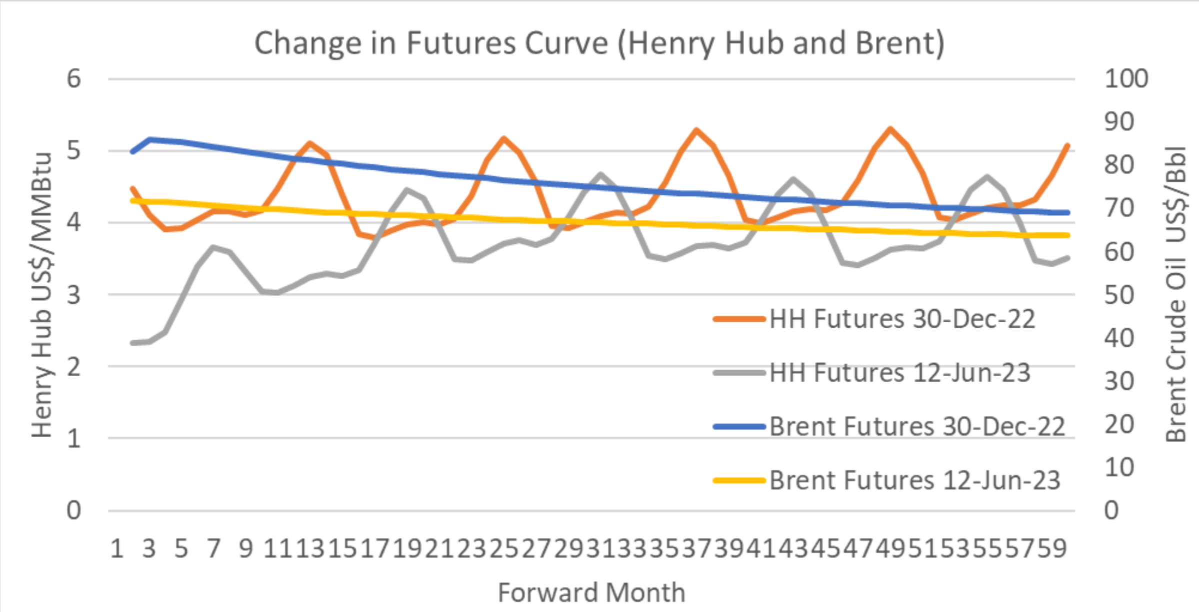
Figure 13: Historical Tender Prices



1.9.4 Estimation of US LRMC

Based on the analysis of Henry Hub futures prices, delivered gas into a Gulf Coast US LNG terminal would be expected to attract a price of US$3.90/MMBtu on average over the medium-term period corresponding to the focus of this report (Jul 2025 to Jun 2028), and it is assumed this would attract a surcharge of 15% to address basis differential, fuel and other charges, reflecting typical LNG tolling terms.

Figure 14: Brent Crude Oil and Henry Hub Gas Futures Curve



The methodology includes an assumed US$2.2/MMBtu tolling charge for use of the liquefaction facilities, and it is noted that in the last 12 months, tolling contracts were agreed, with a rate from US$2/MMBtu to US$2.4/MMBtu levels recently. Partly in consideration of these data points, a change is proposed to the US$2.1/MMBtu tolling assumption that was used in the last report in this series, which is set to US$2.20/MMBtu in this report.

Based on an average delivery distance of 10,000 nautical miles (approximate average for Japan, China and Taiwan) and a round trip fee through the Panama Canal, US Gulf Coast would be expected to have a freight cost estimated at US$2.2/MMBtu for delivery to Asian markets based on average of forward fuel and gas prices from Jul 2025 to Jun 2028. Given that charter rates in recent months have been very volatile as well as spot gas prices, this may not fully reflect LNG vessel charter rates and single voyage charters which could be more or less than this figure which is cost-reflective of a new vessel.

Table 5: Summary of Total LRMC Estimates for June 2028 Compared to December 2022

Components	US$/MMBtu		Description
	Jun 23	Dec 22	
Average Henry Hub Futures during period of interest	3.90	4.45	25 to 60 month ahead futures average
Liquefaction Surcharge	0.59	0.67	15% for fuel and other charges
Liquefaction Tolling Fee	2.20	2.10	
Shipping Charges	2.21	2.40	All-inclusive shipping charges
LRMC Estimate	**8.90**	**9.62**	
Average Brent Crude Oil Futures during period of interest	65.47	72.34	25 to 60 month ahead futures average
% Slope	**13.6%**	**13.3%**	LRMC Estimate divided by Average Brent Price

Based on the analysis of Brent futures prices, US$65.5/bbl is the average futures market price for the period Jul 2025 to Jun 2028. By back calculating the average delivered cost and the average price of oil, the calculated % slope for LRMC in terms of Brent is 13.6%.

2 Price Derivation

Based on the pricing methodology (set out in Appendix III) the estimation of a medium-term oil indexed price for delivery to Asia will follow the process set out below:

2.1 Medium Term Contract History and Data

As noted in the discussion above, GaffneyCline's proprietary access to market activity and the ICIS database of LNG contracts has not identified any documented oil indexed contracts of up to 6 years duration.

2.2 International Tenders

An analysis of oil linked international tenders over the last 12 months has turned up two examples. One of these tenders awarded in April 2023 for delivery in Japan with reported slope to Brent at 17% plus for 12 cargos. Second tender for 36 cargos for delivery in India was partially closed with reported slope to Brent at 15% plus.

Separately, it was reported that Pertamina sold ten cargos at Brent Slope of around 23% from FOB East Kalimantan. Two cargos in 2024, four in 2025 and four in 2026 were offered and the deal was closed on 2 September 2022.

GaffneyCline has considered the following tender assumptions for price derivation.

Table 6: Oil Slope Pricing for Tenders

Buyer/Seller	Date Signed	Delivery Start	Delivery End	Total Cargos	Average Slope
Indian Oil	Jun-23	2023	2026	18	15.5%
Tohoku	Apr-23	2023	2026	12	17.5%
Pertamina	Sep-22	2024	2026	10	23.0%
				Weighted Average	**18.0%**

2.3 US LRMC

From section 2.4 above, the estimate of US LRMC over the relevant period renders a delivered price to Asia of US$8.9/MMBtu which is calculated to be the equivalent of a slope of 13.6%.

2.4 Long Term SPAs

An analysis of oil linked international long-term contracts over the last 12 months has turned up 4 examples as shown in **Table 7**. All four originate from the Middle East, with two to be delivered in Asia on a CIF/DES basis and the other two are FOB contracts. As set out in the methodology, GaffneyCline has estimated that a 5% surcharge would be applied to adjust the long-term contracts to be comparable to mid-term contracts.

Table 7: Oil Slope Pricing for Long-Term SPAs

Date Signed	Contract Start	Contract End	Annual Contract - MTPA	Total Volume - MT	Reported Slope
Jun-23	2026	2041	2.0	30	12.7%
Jan-23	2025	2035	0.8	8	13.5%
Dec-22	2025	2035	2.35	23.5	13.5%
Nov-22	2026	2053	4.0	108	12.8%
				Weighted Average	**12.9%**

2.5 Oil Slope Final Calculation

The starting point for the estimated oil slope is the analysis of medium-term contracts. As noted above, there are no examples which strictly fall within the criteria that could be used as a reference.

Moving to the secondary analysis from which to draw, taking a combination (that depends on the degree of market volatility) of international tenders, US LRMC and long-term SPAs, the following conclusions are derived:

Based on the methodology set out, in a volatile market with low correlation to crude oil such as the one that exists today, it is proposed to place a weighting on the various input parameters in the proportion of 1:2:3.

- Least weighting on international tenders (on the basis they reflect short-term market pressures)
- Medium weighting on US LRMC
- Most weighting on Long Term SPAs

By applying the process to the data and calculations set out above, the following oil slope estimation is calculated (without reference to the non-conforming but illustrative data points from the assessment of medium-term contracts).

Table 8: Overall Weighting for June 2023 Slope

Contract Type	Weights	Slope	Section
Volume weighted international tenders	1	18.0%	3.2
LRMC US exports converted to slope	2	13.6%	3.3
Volume weighted long term deals*	3	13.6%	3.4
Published Slope Estimate		**14.3%**	
*Long term slope of 12.9% is adjusted +5% for financing benefits			

The determination of a 14.3% oil slope represents a decrease of 0.8% (a proportional reduction of 5.3%) in the anticipated medium price of natural gas, compared to Dec 2022.

While the methodology is considered robust and appropriate, it should be noted that the disruption to global supplies over 2022 introduced unpredictability and unprecedented price volatility, making any attempt to forecast price levels exceptionally hard.

However, gas markets have been less volatile in 2023. The prices derived from the analysis set out in this report may be impacted by rapidly changing market conditions, and this should be taken into consideration in the context of any natural gas pricing negotiations in the coming months. This will be revisited in the next Report #4, prepared for the end of December 2023.

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
GJ	Gigajoule
HH	Henry Hub (US gas hub price)
ICIS	International Commodity Intelligence Services
JKM	Platts Japan Korea Marker (TM)
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
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 (approx. 1.055 GJ)
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
PJ	PetaJoule
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

Appendix II
Methodology for Normalising Contract Terms

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. 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 another 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. A FOB off-taker in 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 LNG sales 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 assume 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 cash flow 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 can operate beyond their nameplate capacity, especially after one or two years of operation so buyers can 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 before any formal debottlenecking process).
- Other factors that may influence price include whether the project is in a 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.

Table AII.1: Summary of Contract Term Reconciliation Process

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

Appendix III
Pricing Methodology

Based on the analysis set out in the report on methodology, 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. Short-term international tenders
2. Long-run cost of US LNG Exports
3. Long-term contract signings

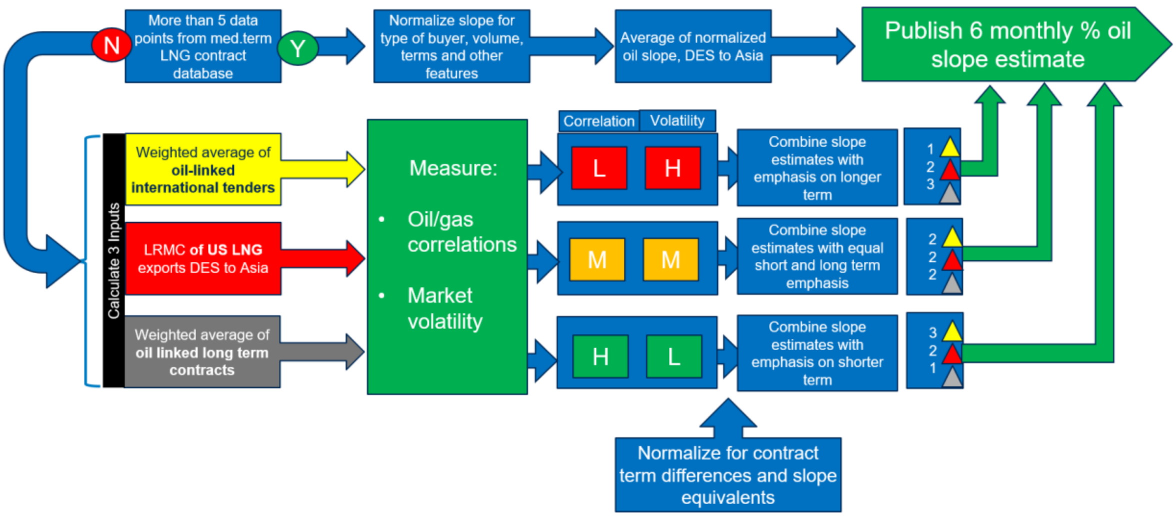
The discussion in the sections above demonstrates that the relationship between these three sources of insight varies, based on the market conditions prevailing. For example, when there is considerable volatility in the market, shorter term/international tender prices can depart substantially from longer 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 methodology is illustrated schematically below:

Figure AIII.1: Methodology Flow Diagram



Note: For the purposes of the flow chart above long-term contracts for input #3 would be those signed in the previous 12 months, but not necessarily flowing. Medium term contracts are those with a duration of less than 7 years, long term contracts would include those of 7 years or more. This cut off is based on the typical tenor of LNG loans of more than 7 years. A 5% price difference would be applied as a mechanism to convert from a long-term LNG SPA to a deemed medium-term price, based on an assumption that a prospective seller would not be able to use the credit support from a firm offtake to lower the cost of an LNG debt instrument.

The 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 derives LNG oil slope estimates.[7]
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

   These three parameters will be combined following the process set out below to produce a single slope data point and combined with the slope data derived from #1 using a simple arithmetic average to generate the final six-monthly oil slope estimates.
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.
6. In the event of lack of tender related oil pricing, or longer-term SPA pricing, or both, the following amended process will be adopted:
   a. When there is no recent tender related oil pricing data the input otherwise derived from this feature of the analysis would be excluded, and the averages re-calculated with reference to inputs #2 and #3. In this case the greatest emphasis will be placed on actual contract terms entered into by unrelated counterparties (of whatever term) and the US LRMC derived pricing would be applied with lesser emphasis in the ratio 3:2 with the greater weighting on longer term SPAs—regardless of market volatility.
   b. In the unlikely event there are no long-term oil linked contracts from which to derive data, the same logic would apply and the weighting between recent oil-linked tender data and US LRMC would be applied in the ratio 3:2 respectively.

[7] If GaffneyCline considers that there are relevant medium term LNG contracts that were executed outside (but reasonably close to) the 12-month period, then to the extent these can be used to place less reliance on the alternative data sources, GaffneyCline may account for these in the calculation of LNG prices as it considers appropriate.

c. Finally, in the event that no oil-indexed data can be sourced *neither* from the recent international tender activity *nor* longer-term signed SPAs the ***previous six-monthly report*** LNG slope will be utlised, and adopted as the current six-monthly price estimate.

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 AIII.1: 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 AIII.2: 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.