Gaffney Cline

Market Advice and Estimates of Contemporary LNG Contract Prices

Report #4 December 2023

Prepared for

Australian Competition & Consumer Commission

February 2024

Document Approval and Distribution

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

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Basis of Opinion

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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

The purpose of this report is to provide an updated slope estimate of medium-term LNG prices, based on an oil index, to inform the ACCC's netback price series up to five years.

Given the strong linkage between international LNG markets, and the supply/demand situation in Eastern Australia, the methodology adopted is intended to:

- Evaluate multiple international pricing methodologies, indices and contract structures and put them in terms of oil indexation, and
- Set these prices in terms that (using the related ACCC reporting on shipping) can be netted back to Australian markets, from the forecast which is expressed in terms of delivered prices in Asia.

Using the approach developed by GaffneyCline (summarized in Box 1 below) an oil slope for medium-term LNG contracts for Asia delivery is currently estimated at 14.0%. This represents a decrease of 0.3% (a proportional reduction of 2.1%) in the anticipated medium price of natural gas, compared to our last report in June 2023.

In summary, the oil slope for this report was derived as follows. Since no medium-term oil-indexed contracts have been entered into within the last 12 months, we move to the secondary analysis, taking a combination of international tenders, US LRMC and long-term SPAs. Based on this methodology we place a weighting on the following input parameters in the proportion of 1:2:3:

- least weighting on international tenders
- medium weighting on US LRMC
- most weighting on long-term SPAs

Applying this process to the data and calculations above, the following oil slope estimation is calculated:

Table 1: Overall Weighting for December 2023 Slope

Contract Type	Weights	Slope	Section
Volume-weighted international tenders	1	16.2%	3.2
LRMC US exports converted to slope	2	12.9%	3.3
Volume weighted long-term deals*	3	14.1%	3.4
Published Slope Estimate		**14.0%**	
*Long-term slope of 13.4% is adjusted +5% for financing benefits			

The forecast oil slope has reduced compared to the previous report due to a combination of the following factors on the plus and minus side:

- lower tender prices driven by reduced spot LNG price
- lower US LRMC prices driven by lower long term US Henry Hub futures
- a slight upward movement due to higher long-term SPAs

To understand this trend in more detail it is useful to assess both supply and demand considerations, and how these have changed between 2022 and 2023.

Demand

- In 2022 European imports of LNG grew by 45 MT (2,570 PJ) as a result of Russian pipeline supplies to Europe being reduced by over 75% between February and October.
- This step change in European LNG demand is likely to be permanent, given the ongoing situation in Ukraine, and the concerns about security of supply that are now prevalent among European buyers.
- Supplying LNG to meet Europe's shortfall is only possible with sufficient installation of additional regasification capacity in European countries to facilitate the increased LNG demand. The supply shortages of 2021 and 2022 were exacerbated by a lack of regasification facilities. This prompted a significant "fast track" investment in regasification infrastructure in Europe, supported by government funding and rapid policy action. Given the short-term requirement for capacity, this is primarily through the installation of Floating Storage and Regasification Units, or FSRUs, which can be brought into service much more quickly than land-based terminals. While Chinese LNG demand fell by 16 MT in 2022, which helped to alleviate LNG shortages in Europe, it has recovered by around 9 MT in 2023 to around 73 MT.
- Furthermore, with the trend back towards more typical international gas pricing, LNG buyers in more price sensitive markets, such as India and Pakistan, are returning to the market with an increase of around 3 MT in 2023 over 2022.
- In the medium term, European LNG imports are expected to continue to replace Russian pipeline supplies and drive an aggregate increase in demand for LNG globally. The impact on LNG pricing in 2023, from Europe's increased LNG imports, was moderate.

Supply

- While Australia and Qatar remained almost static in terms of 2023 exports, both at just under 80 MT, the US ramped up exports from 78 MT to 88 MT in 2023, an increase of 13% year on year.
- This trend is set to continue, as in early 2023, Venture Global's Plaquemines project and Sempra's Port Arthur project announced FID, and other projects, including the Energy Transfer export terminal at Lake Charles, Texas LNG and Commonwealth LNG, are widely expected to follow suit in the first half of 2024. The impact of a recent White House policy review on LNG, referenced in more detail below, is yet to be fully factored in however.
- Over 40 MTPA (2,300 PJ) of new regasification capacity in countries with increased LNG demand is projected to be operating or under construction by 2025. In market terms, this increase in demand is the equivalent of over half of the Australian LNG exports in 2022.
- In addition to the near-term growth anticipated in the US referenced above, new supplies will be available in the medium term with the expansion underway in Qatar,

further expansion of capacity at LNG Canada and the much-delayed Mozambique development, and the LNG export facility under construction in Senegal/Mauritania.

The price responses to the factors above have created a more orderly and less volatile pricing period over the last 6 months, which has also resulted in lower prices. While European demand, especially in the northern hemisphere winter, creates upward pressure on prices, temperature related demand so far this winter has been muted. These supply and demand are in general creating lower futures prices in the major traded markets of Europe and Asia.

A measure of how materially prices have stabilised is demonstrated by examining average global prices in 2022 and 2023, compared to average Brent prices. This shows that, on an oil indexed basis, spot prices in Asia diminished from 35% Brent to 17% with European prices falling from 42% to 16%.

Longer term, one of the main sources of demand uncertainty for the LNG sector arises from the global policy developments relating to climate and carbon intensity. This is beginning to affect future LNG investment as developers and lenders start to assess the likely effect on LNG demand.

One such development is the recent announcement by the White House[1] of a pause in LNG project approvals while a study of carbon and climate implications is carried out. This may affect the future growth in LNG exports and could have an influence on natural gas pricing towards the end of the forecast period. However, this announcement is too recent to be visible in the data used to derive this price outlook and will be re-assessed in the next report in this series.

Similar legislative measures are emerging in Australia. For example, the Western Australia Parliament introduced the Petroleum Legislation Amendment Bill 2023 (second reading) on 29 November 2023, which contains a number of measures relating to lowering CO_2 emissions, mirroring legislation in Victoria and Queensland, and aspects of federal law, but these features are also insufficiently developed to be visible in pricing considerations.

[1] https://www.whitehouse.gov/briefing-room/statements-releases/2024/01/26/fact-sheet-biden-harris-administration-announces-temporary-pause-on-pending-approvals-of-liquefied-natural-gas-exports/

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 to 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 forecast 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.

For the purposes of this price derivation methodology ***volatility*** is measured by reference to trailing Relative Standard Deviation (RSD)[3] applied to the EAX gas price index for Asia. One year trailing EAX RSD was typically 10% to 25% (2012 to Q1-2019). Since Q2-2019, EAX RSD has been mostly above 30%. For the purposes of determining which weighting to apply, we use low volatility as less than 20%, medium volatility as 20% to 30% and high volatility as anything above 30%.

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

[3] RSD is defined as the ratio of the standard deviation to the mean. It shows the extent of variability in relation to the population's mean. RSD is a dimensionless number.

Discussion

1 Overview of LNG Market Developments

1.1 European Supply Disruption

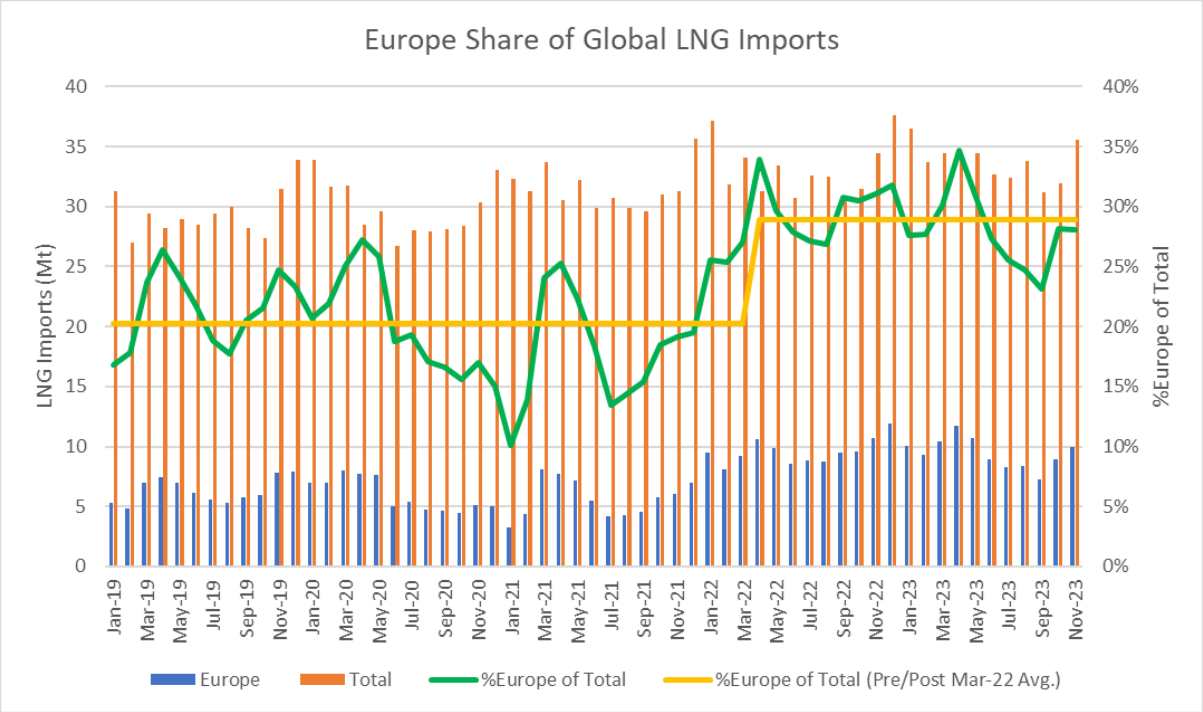
The medium to long-term effects of the disruption to European gas supplies due to the Russia-Ukraine conflict appears to have resulted in a structural shift in LNG flows. This is evidenced by the continuing increase in LNG market share for European buyers, and no apparent change in the shortfall in Russian gas imports to Europe over the last 12 months. 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 76% to recent average of 56 MCM per Day as shown in Figure 1.

Figure 1: Russian Exports to Europe

Source: IEA, GaffneyCline Analysis

As can be seen in Figure 2 below, the European share of US LNG exports rose from about 20% pre-conflict to nearer 29% 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, and Brunsbuettel. Further vessels are planned in early 2024 at Mukran, on the Island of Rugen, Stade and an additional FSRU at Wilhelmshaven. In France, an FSRU was commissioned in Le Havre recently. The speed with which these floating facilities were conceived and executed has alleviated some of the medium-term concerns over European supplies, though as the heating season evolves through the remainder of 2024 gas buyers will be looking carefully at the supply situation.

Figure 2: Increasing Share of US LNG Exports Delivered to Europe

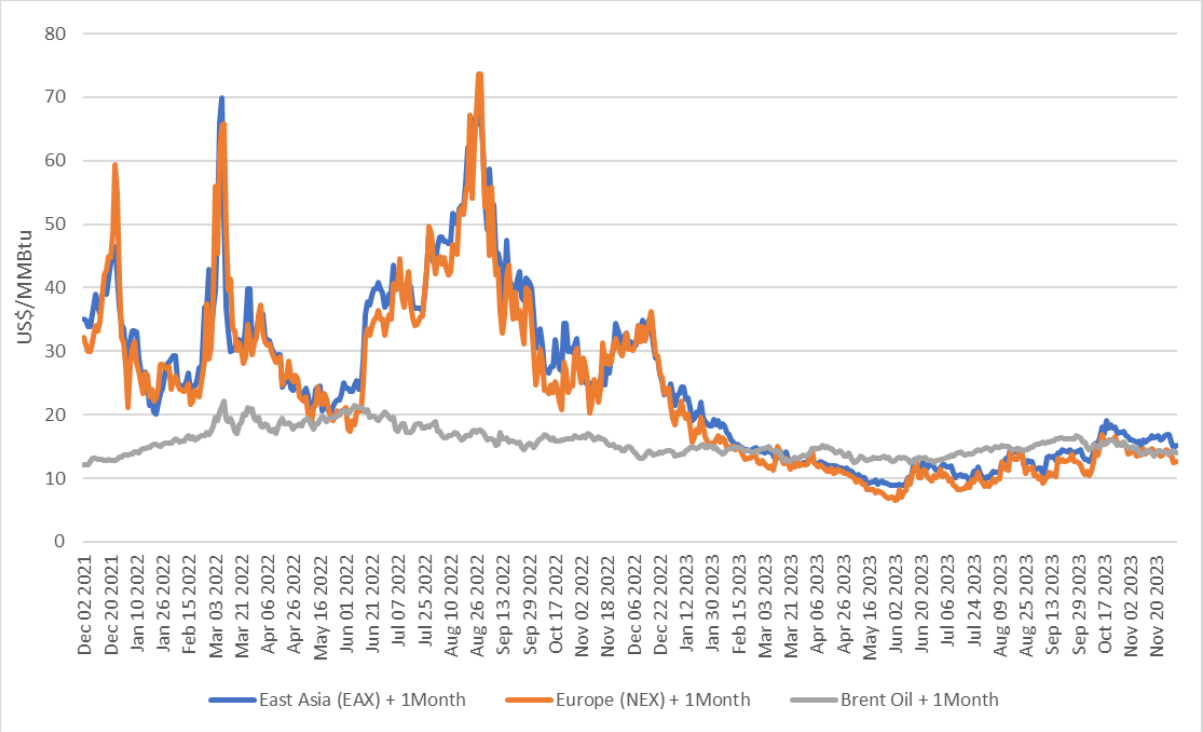


Source: ICIS, GaffneyCline Analysis

1.2 Impact on Wholesale Natural Gas Markets

The price shocks that characterised late summer and the start of winter 2022 have not been repeated in recent months, with both demand falling (with the European summer months and energy efficiency measures being introduced) and supply availability increasing (Figure 3).

Figure 3: East Asian and European Gas Prices in Last Two Years



Source: ICIS, GaffneyCline analysis

In November 2023 the wholesale price of natural gas in Continental Europe, measured by reference to the TTF hub had reduced to about US$14/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.

In fact, during the first half of 2023 compared to the first half of 2022, government subsidies of natural gas consumer prices in Europe dropped from 27% to 19%, which resulted in a slightly

higher price to the consumer. However, prices for winter of 2023/24 are continuing to ease, given recent wholesale price trends.

Since September 2021, €651 billion[4] has been allocated and earmarked across European countries to shield consumers from the rising energy costs, and the recent stabilisation of natural gas prices has alleviated what would have been a significant strain on many European nations' GDP had prices remained elevated.

1.4 Price Arbitrage and Short-Term Trading

Based on 2022 full year results, it is clear that global LNG trading activities during that year resulted in some exceptionally high earnings, albeit with a considerable strain placed on balance sheets and credit resulting from large margin calls and contingent liabilities. In some cases, these trading activities are an integral part of the businesses associated with LNG supply, but in others these are pure profit maximising activities, 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. The more typical trading conditions that exist in later half of 2023 will mitigate this effect and put downward pressure on oil slope indices experienced by gas buyers.

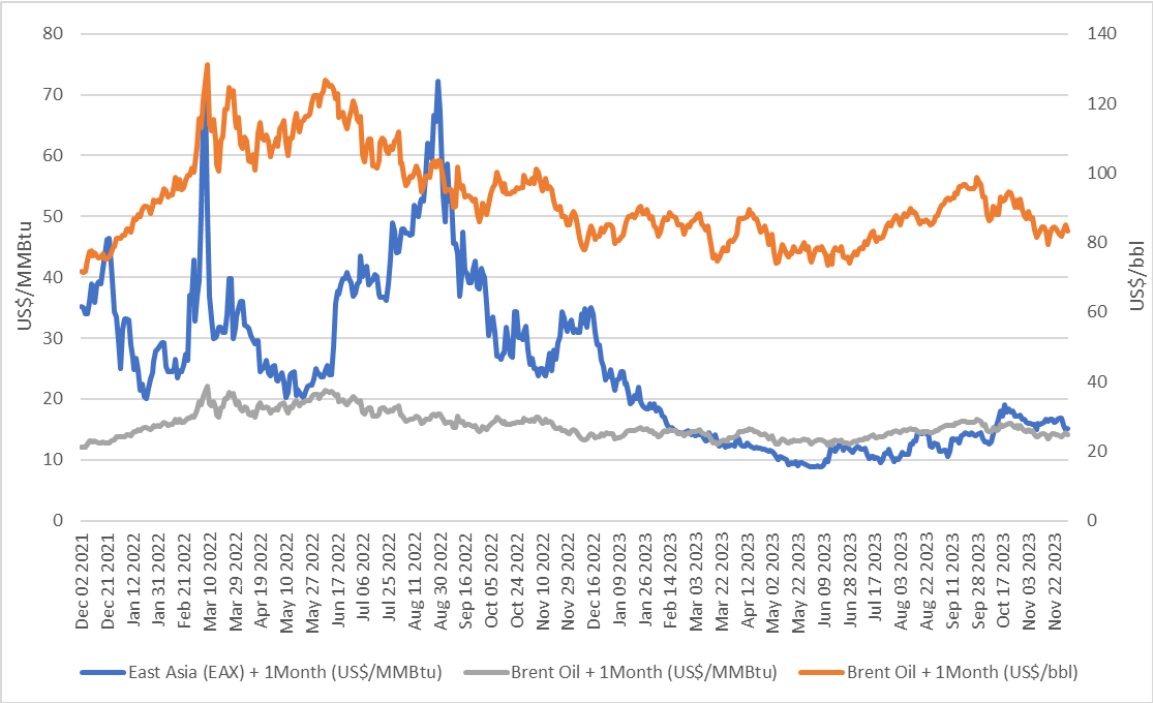
Trading performance in 2023 was more muted, partly due to the reduced volatility. This is because volatile commodity prices create a large profit pool for trading entities, but also carry more risk of losses. A more recent detailed analysis of 2022 trading profits shows that they were quite variable, and some short-term strategies were more successful than others. For example, during the financial year commencing January 1st 2022, Shell and TotalEnergies, who took positions in the expectations of rising prices in Asia, generated substantial margins; whereas BP, who focused on Atlantic basin trades, sustained losses which contributed to BP's third quarter profits of $3.3 billion being 20% lower than analysts' forecasts.

1.5 Oil Price Stability and Impact on Pricing Trends

During this period of wholesale gas price instability, oil prices have remained stable, relatively speaking, and this has set up a pricing dynamic which is driving gas sale and purchase decisions. As seen in Figure 4, heat equivalent Brent crude oil prices are relatively stable within the range of 12 to 22 US$/MMBtu in last two years. For the same period, East Asian gas prices have ranged between 9 to 72 US$/MMBtu.

[4] National fiscal policy responses to the energy crisis, 26 June 2023 https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices

Figure 4: East Asian Gas Prices and Brent Crude Oil Prices in Last Two Years



For wholesale gas 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.

Japanese LNG supplies being largely oil indexed (JCC), and European supplies are largely based on gas indices. Given the ease with which LNG can flow from one market to another, this creates a market mechanism to support a correlation between oil and gas pricing.

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.

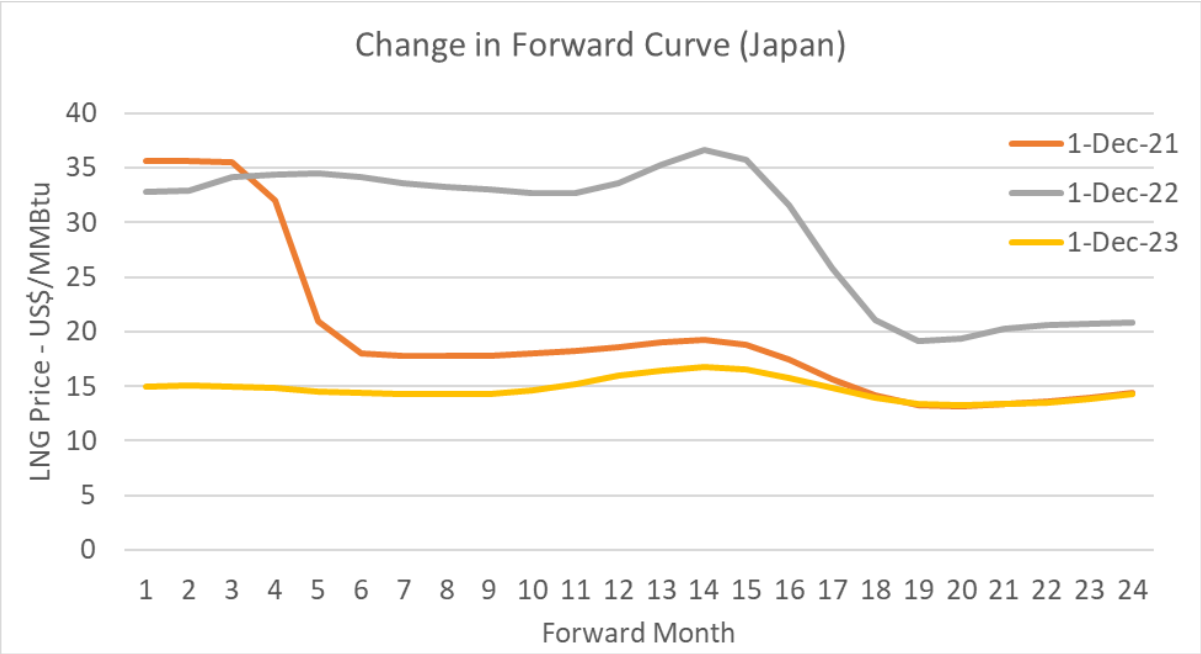
1.6 Forward Market Outlook

As we progress into Q1 2024, it appears that the easing in forward gas prices evident in the market outlook for June 2023 (that was set out in our previous report in this series) has 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 in 2022. Furthermore, additional LNG supplies from the US Gulf Coast, as well as other

projects under development such as Mozambique, Senegal all suggest that additional supplies can be used to compensate for the shortfall in the medium to long term, particularly with the installation of regasification infrastructure in countries with increased LNG demand.

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 transacted, has fallen back to levels closer to the pre-crisis curve from December 2021 and has dropped significantly since the outlook 12 months ago in December 2022.

Figure 5: Change in Gas Forward Price for Japan Delivery



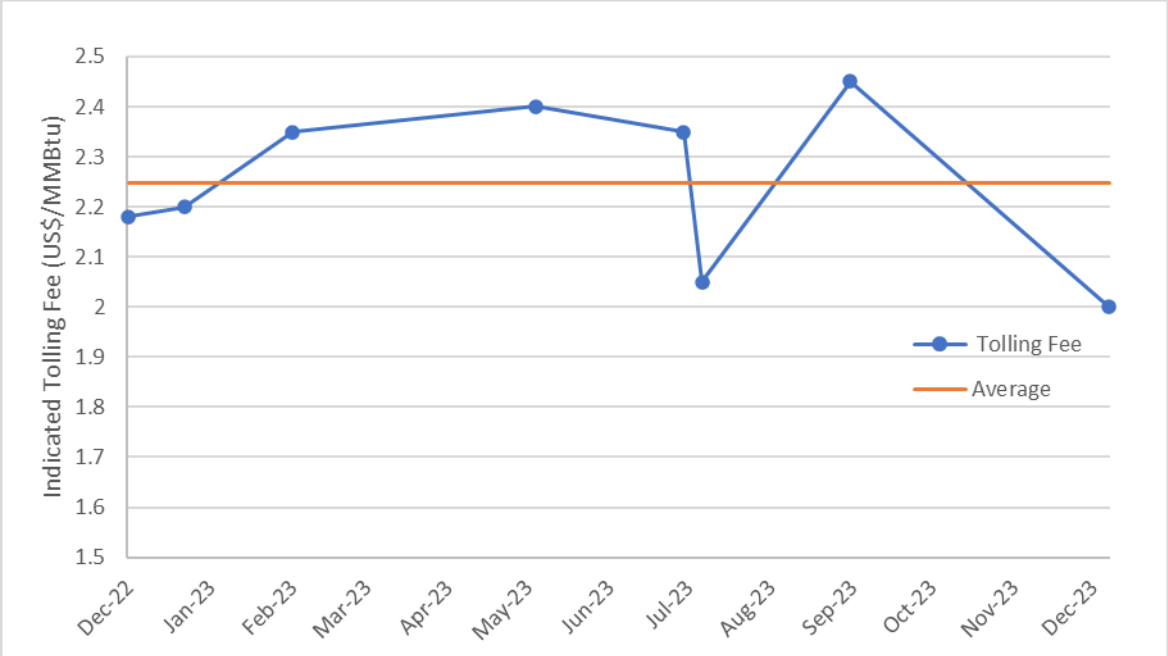
Source: ICIS, GaffneyCline analysis

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. With recent decreases in prices imported volumes have recovered with an increase of over 15% in April 2023 to November 2023, compared to the same period in 2022. East Asian LNG Prices (EAX+1Month) averaged US$30.3/MMBtu from April 2022 to March 2023 and decreased to US$12.7/MMBtu in April 2023 to November 2023.

The disparity between spot prices and long-term contract prices created more demand for new long-term supplies in 2022. This is evidenced in several long-term deals (15-20 years) signed in the first half of 2023 with US suppliers, predominantly by Chinese LNG importers. These long-term deals have been reported to include tolling rates in the US$2.00/MMBtu to US$2.50/MMBtu range. However, growing demand for LNG, especially for projects that can deliver in the 2025/26 timeframe, and increasing concerns over inflation impacting construction costs suggests that there is upward pressure on this tolling fee. For these reasons, we are once again increasing our tolling cost assumption from US$2.20/MMBtu to US$2.25/MMBtu (an increase of 2.3%) when assessing the long-term pricing estimates for US exports.

Data from the latter half of 2023 appears to suggest that the trend back towards longer-term LNG contracting has halted, with LNG traded outside long-term arrangements increasing by 12 MT in 2023 compared to the previous year.

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

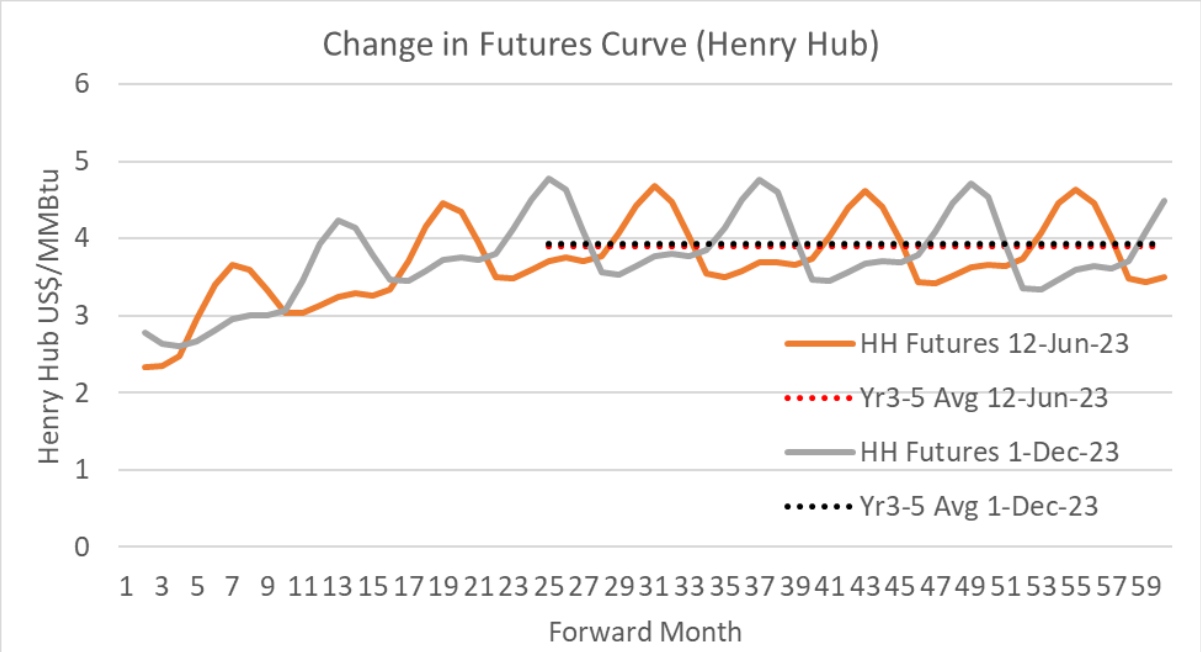


Source: ICIS, GaffneyCline analysis

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$4.23/MMBtu for January 2025. With only about 10% of US gas production destined for LNG exports, the impact of global pricing is muted. However, the upward trend in price reflects an anticipated continued demand for feed gas for LNG export in the coming year, with a proportional need for greater supply, coupled with an increasing need to develop gas with a higher wellhead breakeven price. Translated into oil slope levels, this would place January 2025 oil indices, on a delivered to Asia basis, at around 12.3%, based on the January 2025 Brent futures price of US$76.3/barrel[5].

[5] $4.23/MMBtu Henry Hub with 15% allowance for fuel and basis comes to $4.86, then adding $2.25/MMBtu as our current estimate of tolling fee and $2.25 current freight estimate to Asia comes to a total of $9.36/MMBtu delivered, which divided by the January 25 futures oil price of $76.28/barrel comes to an imputed oil index of 12.3%

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 (September 2023 to November 2023), the slope would sit at 16.8%. For the same contracts the slope was 13.7% based on average prices over Q2 2023. This is an indication of spot LNG markets have tightened to some extent, since the publication of our previous report, likely due to winter related demand in northern hemisphere.

1.7 Pricing Trends / Market Sentiment

One of the legacies of the gas market disruption has been a reversal of the trend to rely more on spot and short-term trades, and a return to more reliable long-term take or pay contracts. Over 100 long-term LNG contracts have been signed since the start of the Russia/Ukraine conflict. In 2022, over 70 MT of LNG contracts were concluded. This represents a 100% increase when compared to the average over the last five years. In 2022, 90% of contracts concluded had a duration over 15 years in length, with 65% over 20 years in length, signaling a long-term commitment to LNG from buyers. While the rush to sign up long-term LNG supplies appears to have abated somewhat in 2023, LNG buyers continue to manage their portfolios with a higher proportion of firm, committed demand than in previous years.

Oil indexation for long-term contracts remains common, partly as oil price risk is considered less of a concern to lending institutions and can lower the cost of debt that applies to LNG projects. Furthermore, the relative immaturity of many wholesale “gas on gas” indices such as TTF and NBP in Europe, and JKM in Asia has meant that extreme short-term price spikes have been relatively frequent and can be difficult to hedge with financial derivatives. However, during 2023 QatarEnergy has signed four major supply contracts with Europe, at least one of which is said to be on a discount to TTF, and this trend is likely to continue as these price indices attract greater liquidity and hedging potential.

Although a purely gas indexed LNG contract is still less common, so-called “hybrid” contracts are now becoming more widespread. These include elements of both oil price and other gas

indices. Notably, Henry Hub, in the US has remained relatively stable over the last several months during the price dislocations in other markets, and is frequently combined with oil in hybrid LNG contracts.

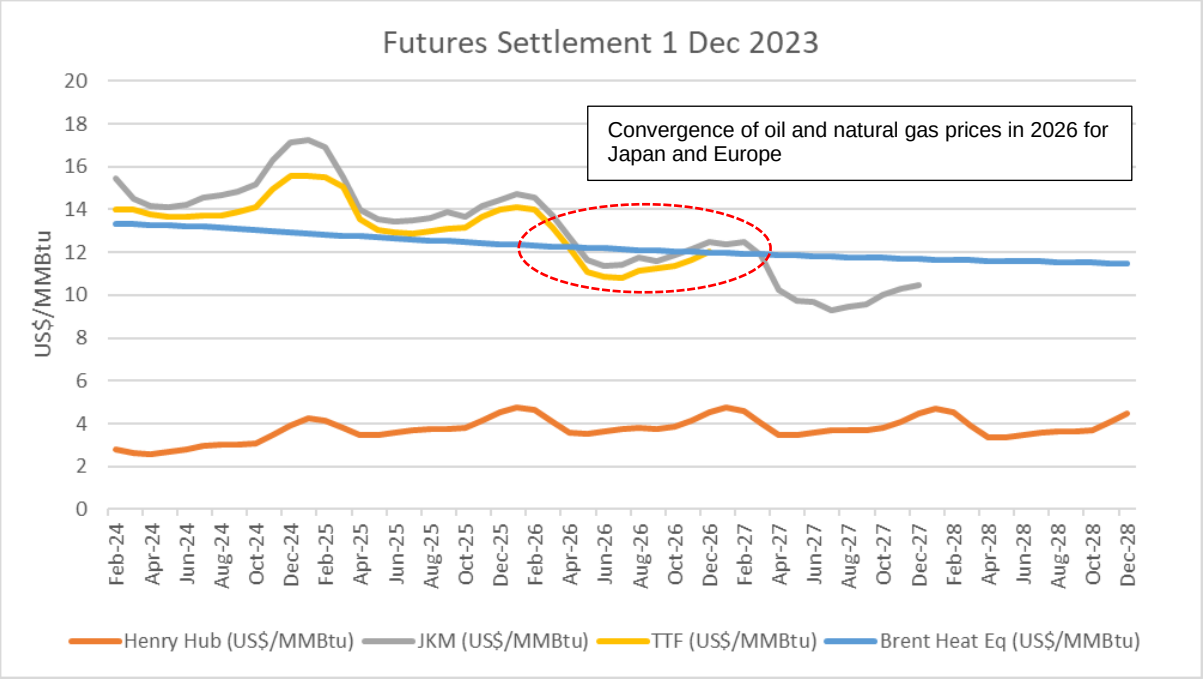
Oil indexation is also common in so-called “equity marketing” arrangements, whereby the equity investors in an LNG project will sell the output on an FOB basis to a marketing affiliate, who will combine the volumes in a much larger portfolio of LNG purchased volumes, and sales that can provide a combination of short, medium and long-term.

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.

Although the supply disruptions of 2021/22 meant that the relationship between the price of natural gas and oil became highly uncorrelated, this trend has now reversed, although with weaker drivers than in previous decades. 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 continuing 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 similar to Europe occurs. Spot prices should ease with additional LNG supplies coming onstream in 2026/27. It should be noted that given the immaturity of the forward market, and lack of liquidity, unlike for example Brent or Henry Hub, the futures market relating to TTF and JKM is typically limited to about a 24 month look-ahead.

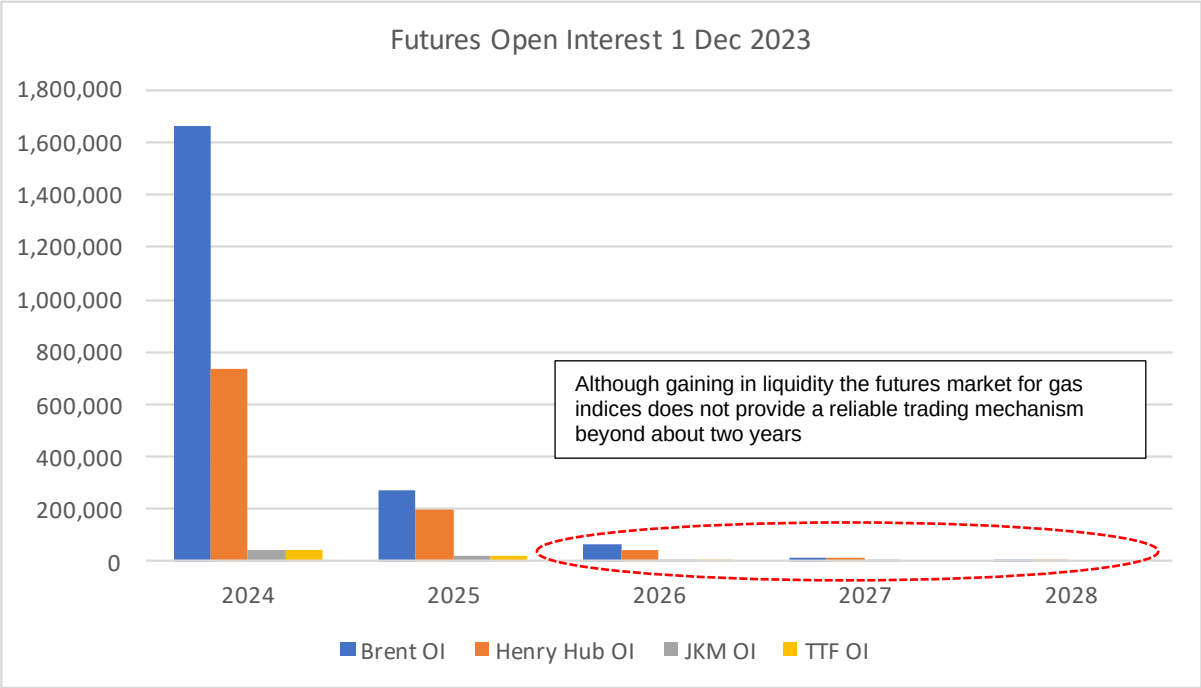
Figure 8: Futures Market Price Curves



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. As previously noted, the reliability of JKM, as well as TTF futures beyond about 2 years, 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



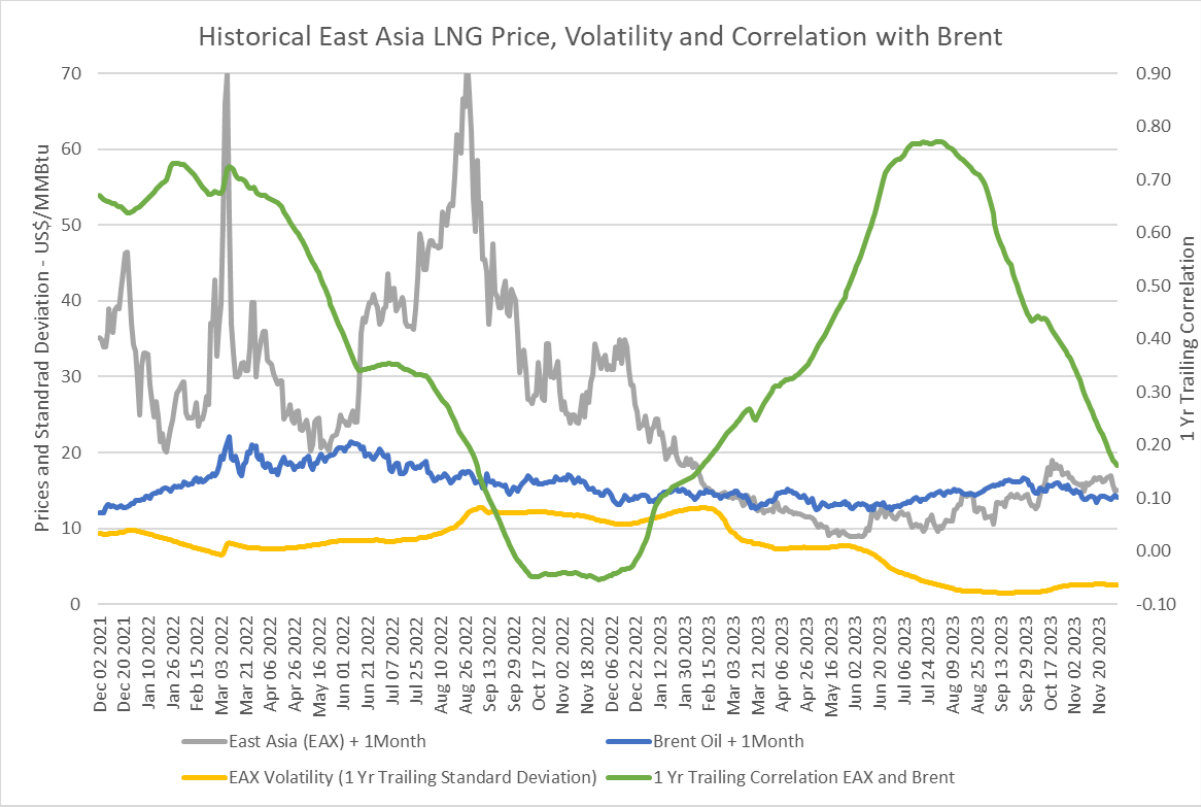
Source: ICE, CME and GaffneyCline Analysis

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[6]), volatility and correlation with Brent crude oil prices are shown in the next chart.

[6] 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

The shift towards lower carbon forms of energy is increasing the attention that is being given to its likely impact on natural gas demand and pricing paradigms.

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.[7]

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 14.0% to around 14.7%.

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

Although prices are returning to closer to average levels of last five years the impact of the volatility in 2021/22 will be evident in some of the analysis. For example, the last five-year average is significantly higher than the median due to the very high positive skewed markets seen in 2021-2022.

Table 2: Average Regional Prices

Prices US$/MMBtu	East Asia +1month	North Europe +1month	ICIS Brent +1month	Henry Hub +1month
5-year Average	14.9	13.6	12.3	3.5
5-year Median	10.2	8.2	12.3	2.7
31-May-2023	9.5	8.3	13.1	2.3
1-Dec-2023	15.1	12.7	14.1	2.8

In spite of the downward trend of recent months, there is some risk to supply in the first half of 2024, which could place upward pressures on pricing compared to the analysis set out in the report. These may arise from such things as:

- Colder than normal temperatures in the last part of the northern hemisphere heating season
- Continuing disruption of shipping in the Red Sea resulting in disruption of LNG traffic
- Unplanned outages of LNG facilities, pipeline failures or disruptions

As a result, shorter-term gas sale and purchase agreements could still carry a 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.

General market sentiment and reporting suggests that long term contracts which commence in the pre-2026/27 time period carry a premium, potentially in the range 15-17% while contracts with deliveries in the post 2028 timeframe are in the 12% to 15% range.

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

1.9.1 Medium-Term Oil Indexed Contracts

No Medium-Term Oil[8] 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:

- Japan's Chugoku Electric awarded a two tranche buy tender in March 2023, for 2023-2025 and 2026-2030 delivery, to a Japanese trader and British oil major. The 2023 to 2025 tranche is reported to be priced at a slope of between 20% to 23% to Brent. The 2026 to 2030 tranche was awarded at a slope of around 13% to 14%.
- 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 at a slope of 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 64 long-term LNG deals were agreed upon during the last 12 months (Dec 2022 to Nov 2023), which compares with 46 in 12 months period a year earlier. Of these signed in last 12 months, 25 were signed with existing or prospective US sellers. Table 3 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 Oman, Qatar, and Mexico.

Table 3: Recent Long-Term Sale and Purchase Agreements (by Origin)

Origin	Dec 2022 to Nov 2023		Dec 2021 to Nov 2022	
	# of Contracts	Contracted Volume (MT)	# of Contracts	Contracted Volume (MT)
United States	25	552	31	780
Oman	13	103	-	-
Qatar	6	435	4	163
Mexico	6	172	2	92
Others	6	34	3	24
Undeclared	8	72	6	25
Total	**64**	**1,368**	**46**	**1,084**

[8] 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.

As shown in Table 4 below, the destination for most of the contracts 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 from USA.

Table 4: Recent Long-Term Sale and Purchase Agreements (by Destination)

Destination	Dec 2022 to Nov 2023		Dec 2021 to Nov 2022	
	# of Contracts	Contracted Volume (MT)	# of Contracts	Contracted Volume (MT)
China	12	319	18	378
Japan	8	81	-	-
Germany	4	113	3	70
Bangladesh	3	68	-	-
Others	12	305	4	47
Undeclared	25	482	21	589
Total	**64**	**1,368**	**46**	**1,084**

The bulk of the contracts signed are indexed to Henry Hub. There was a resurgence of oil slope-based contracts mostly signed by Asian buyers for LNG originating primarily from the Middle east. A large share of Henry Hub pricing is a result of pricing terms associated with upcoming LNG projects in the USA and Mexico.

Table 5: Recent Long-Term Sale and Purchase Agreements (by Pricing Mechanism)

Contract Type	Dec 2022 to Nov 2023		Dec 2021 to Nov 2022	
	# of Contracts	Contracted Volume (MT)	# of Contracts	Contracted Volume (MT)
Henry Hub	22	544	31	812
Oil Slope	12	255	3	133
Spot Price or Mixed	3	39	1	4
Undeclared	27	530	11	135
Total	**64**	**1,368**	**46**	**1,084**

1.9.3 International Tenders

In the last 12 months (December 2022 to November 2023), a total of 408 international tenders were issued of which 243 were on the buy side and 165 were on the sell side.

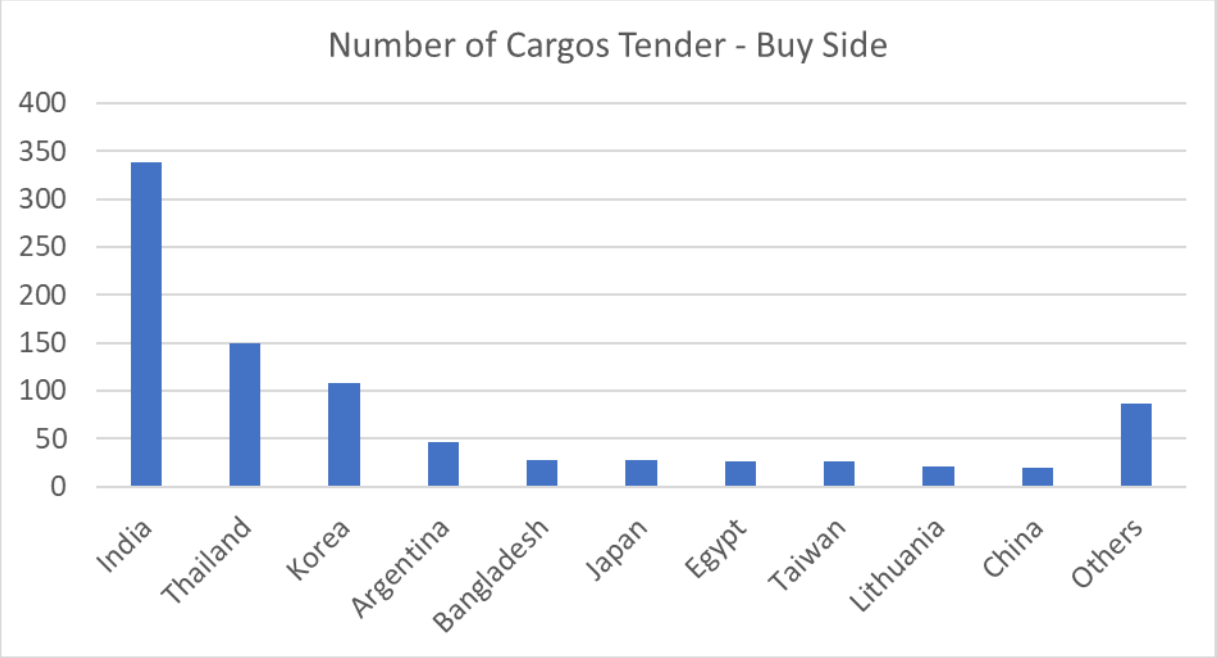
65% of these tenders were for a single cargo, and 21% involved more than 1 and less than 5 cargoes. Only 14% of tenders were for 5 or more cargoes. Total cargos put on tenders were 1,204.

In terms of the number of cargos tendered, India is a dominant player on the buy side and accounted for 338 out of a total of 880 (approximately 38%) of the buy side cargos tendered. Thailand and Korea are other major buyers using tenders. On the sell side

a total 324 cargos were tendered. USA accounted for 40% sells side tenders and other major players were Angola and Australia.

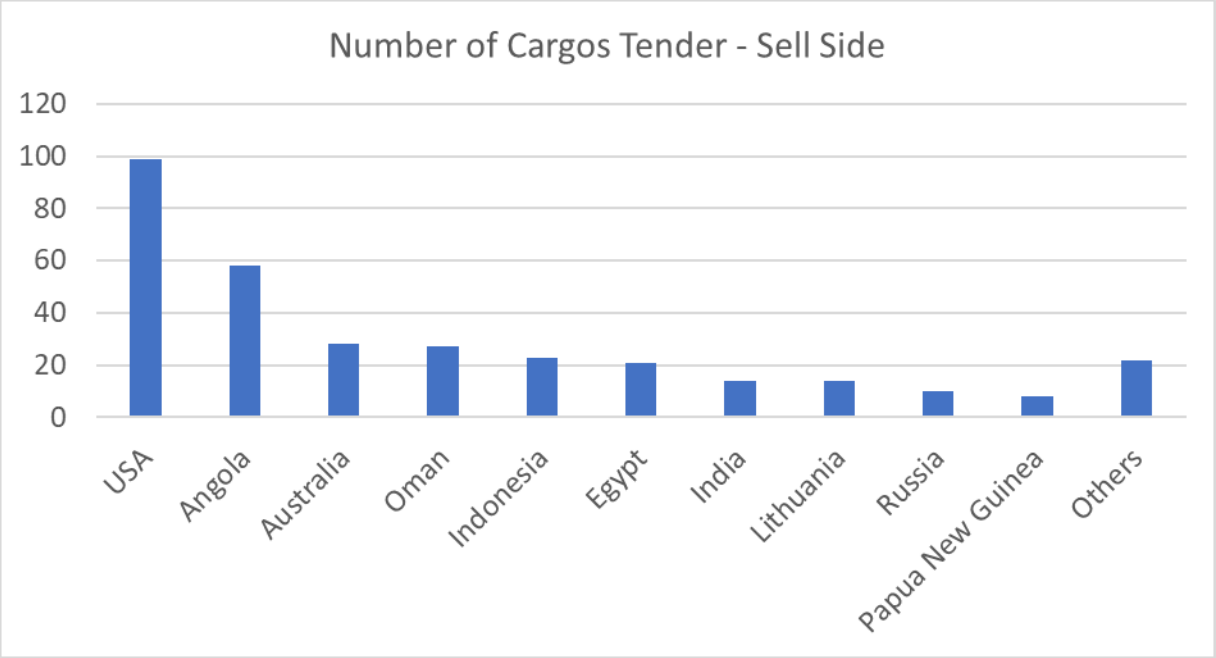
Figure 11 shows that the international tender data can be used as a good reference for Asia deliveries which will have most influence on market conditions in Australia (after applying the netback to Australia using ACCC methodology). Seven of the top 10 players in the international tender markets are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

Figure 11: Buy Side Cargos Tender by Country (12 months ending 30 Nov 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 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 30 Nov 2023)



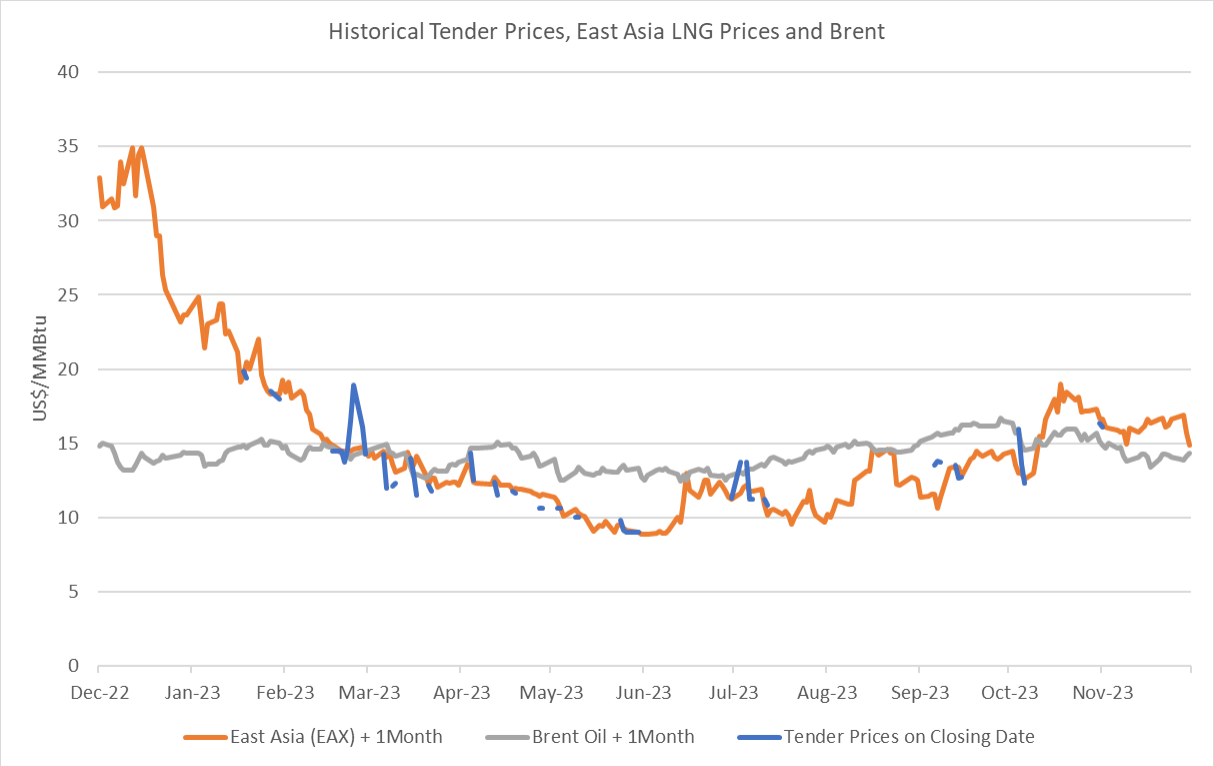
In terms of contract pricing, limited information is available. Based on available information most of the cargos were tendered at a fixed price. NE Asian marker and TTF linked tenders were second and third preferred choices.

Table 6: Recent Tenders by Pricing Mechanism (12 months ending 30 Nov 2023)

Contract Pricing Type	Buy Side	Sell Side	Total
Fixed Price	214	113	**327**
NE Marker	82	26	**108**
TTF linked	39	16	**55**
Henry Hub linked	11	2	**13**
Oil Slope	-	13	**13**
Unknown	534	154	**688**
Total	**880**	**324**	**1,204**

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.

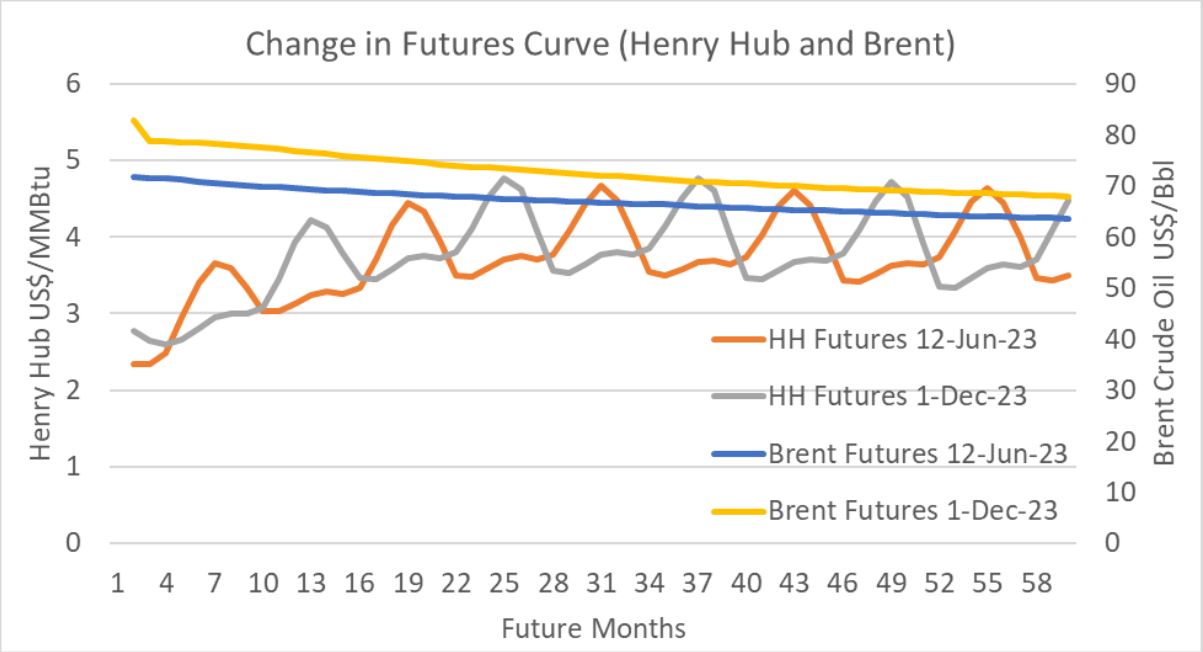
Figure 13: Historical Tender Prices



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$3.94/MMBtu on average over the medium-term period corresponding to the focus of this report (Jan 2026 to Dec 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$2.25/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$2.5/MMBtu levels recently. Partly in consideration of these data points, a change is proposed to the US$2.2/MMBtu tolling assumption that was used in the last report in this series, which is set to US$2.25/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$2.25/MMBtu for delivery to Asian markets based on average of forward fuel and gas prices from Jan 2026 to Dec 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 7: Summary of Total LRMC Estimates for Dec 2023 Compared to Jun 2023

Components	US$/MMBtu		Description
	Jun 23	Dec 23	
Average Henry Hub Futures during period of interest	3.90	3.94	25 to 60 months ahead futures average
Liquefaction Surcharge	0.59	0.59	15% for fuel and other charges
Liquefaction Tolling Fee	2.20	2.25	Average of indicated USA LNG tolls for past 12 months
Shipping Charges	2.21	2.25	All-inclusive shipping charges
LRMC Estimate	**8.90**	**9.03**	
Average Brent Crude Oil Futures during period of interest	65.47	70.14	25 to 60 months ahead futures average
% Slope	**13.6%**	**12.9%**	LRMC Estimate divided by Average Brent Price

Based on the analysis of Brent futures prices, US$70.1/bbl is the average futures market price for the period Jan 2026 to Dec 2028. By back calculating the average delivered cost and the average price of oil, the calculated % slope for LRMC in terms of Brent is 12.9%.

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 twelve months has turned up thirteen examples but only three tenders had oil slope reported. One of these tenders awarded in April 2023 for delivery in Japan with reported slope to Brent at 17% plus for 12 cargos. A second tender for 36 cargos for delivery in India was partially closed with reported slope to Brent at 15% plus. Third tender is for single cargo sold by NNPC at 11.5% Brent slope + 0.61.

GaffneyCline has considered the following tender assumptions for price derivation.

Table 8: Oil Slope Pricing for Tenders

Buyer/Seller	Date Signed	Delivery Start	Delivery End	Total Cargos	Average Slope
NNPC[9]	Jul-23	2023	2023	1	12.3%
Indian Oil[10]	Jun-23	2023	2026	18	15.5%
Tohoku	Apr-23	2023	2026	12	17.5%
				Weighted Average	**16.2%**

2.3 US LRMC

From section 1.9.4 above, the estimate of US LRMC over the relevant period renders a delivered price to Asia of US$9/MMBtu which is calculated to be the equivalent of a slope of 12.9%.

2.4 Long-Term SPAs

An analysis of oil linked international long-term contracts over the last twelve months has turned twelve examples but oil slope information could be established for only five contracts as shown in Table 9. All five originate from the Middle East, with three 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.

[9] Slope adjusted to at Brent price of US$80/bbl reflective of prices during tendering.
[10] Partial award assumed to be half of tendered quantity.

Table 9: Oil Slope Pricing for Long-Term SPAs

Date Signed	Contract Start	Contract End	Annual Contract - MTPA	Total Volume - MT	Adjusted DES Japan Slope[11]
Nov-23	2026	2041	1	15	14.4%
Jun-23	2026	2053	4	108	12.6%
Jun-23	2026	2041	2.0	30	13.7%
Jan-23	2025	2035	0.8	8	15.4%
Dec-22	2025	2035	2.35	23.5	15.4%
				Weighted Average	**13.4%**

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:

First, as of the end of 2023, the 1-year trailing correlation for EAX with Brent is 0.17 (<40% defined in the methodology as low correlation) which is illustrated in Figure 10. Similarly, EAX Relative Standard Deviation (RSD) was 40%, suggesting ***high volatility.***

Based on the methodology set out, in a volatile market with low correlation to crude oil such as the one that existed at the end of 2023, 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).

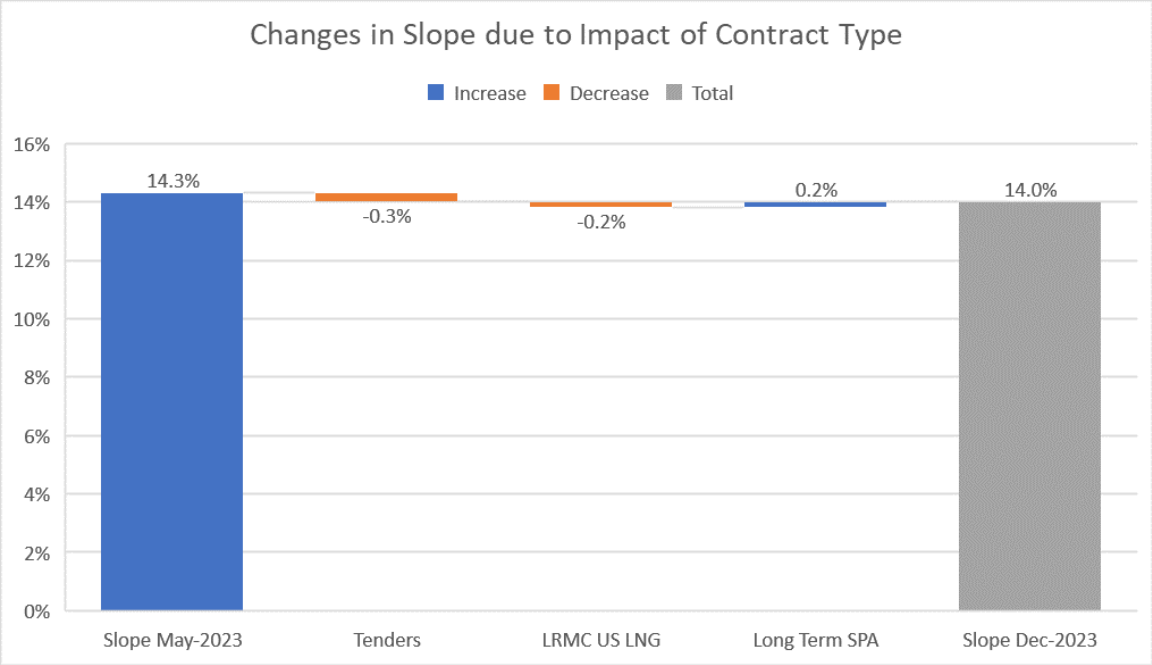
[11] Slopes adjusted to reflect estimated shipping charges from the Middle East to Northeast Asia (China, Korea and Japan)

Table 10: Overall Weighting for December 2023 Slope

Contract Type	Weights	Slope	Section
Volume weighted international tenders	1	16.2%	3.2
LRMC US exports converted to slope	2	12.9%	3.3
Volume weighted long term deals*	3	14.1%	3.4
Published Slope Estimate		**14.0%**	
*Long term slope of 13.4% is adjusted +5% for financing benefits			

The determination of a 14.0% oil slope represents a decrease of 0.3% (a proportional reduction of 2.1%) in the anticipated medium price of natural gas, compared to our report in June 2023.

Figure 15: Change in Slope Derivation: Waterfall Chart



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, prepared for the end of June 2024.

Appendix I
Glossary of Terms

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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

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Appendix II
Methodology for Normalising Contract Terms

Australian Competition & Consumer Commission
February 2024

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 input into the master project economic model. This would then 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

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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

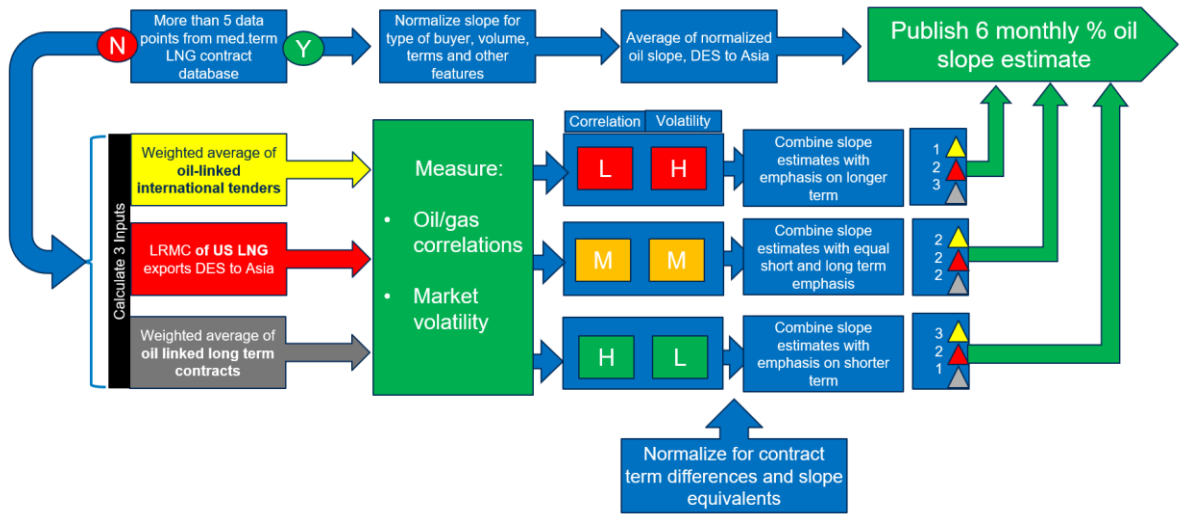
The discussion in the sections above demonstrates that the relationship between these three sources of insight varies, based on the market conditions prevailing. For example, when there is considerable volatility in the market, shorter term/international tender prices can depart substantially from longer 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.[12]
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. The next step in the price derivation is to apply the appropriate weightings to these three averages, based on both the degree of correlation between oil and international gas indices, and secondly the degree of volatility that exists. This is done by reference to the 12 months of market data prior to the relevant price forecast being derived. Correlation is determined through standard statistical analysis, and volatility is determined by reference to the Relative Standard Deviation (RSD)[13] applied to the EAX gas price index for Asia. One year trailing EAX RSD was typically 10% to 25% (2012 to Q1-2019). Since Q2-2019, EAX RSD has been mostly above 30%. For the purposes of determining which weighting to apply, we use low volatility as less than 20%, medium volatility as 20% to 30% and high volatility as anything above 30%. 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.

[12] 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.

[13] RSD is defined as the ratio of the standard deviation to the mean. It shows the extent of variability in relation to the population's mean. RSD is a dimensionless number.

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.
    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 utilised, 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.