LNG netback review

Draft decision paper

July 2021

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Acronym List

C&I	commercial and industrial
DES	delivered ex-ship
DFDE	dual-fuel diesel electric
FOB	free on board
GSA	gas supply agreement
JCC	Japanese Crude Cocktail
JKM	Japan Korea Marker
LNG	liquefied natural gas
LRMC	long run marginal cost
NBP	National Balancing Point
SPA	Sale and Purchase Agreement
TTF	Title Transfer Facility
Organisations	
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ICE	Intercontinental Exchange
Platts	S&P Global Platts
RBA	Reserve Bank of Australia
Units	
BCM	Billion cubic metres
MMBtu	Million British thermal units
mtpa	million tonnes per annum
GJ	Gigajoule
PJ	Petajoule

TCF	Trillion cubic feet

Glossary

ACCC's East Coast Gas Inquiry 2015: The ACCC's inquiry into the east coast gas market in 2015, as reported on in April 2016.

Bunker fuel: The fuel oil used by marine vessels.

Delivered ex-ship (DES): The seller of a shipment bears all associated risks and costs until the shipment arrives at the agreed destination port.

East coast gas market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria and Tasmania.

Free on board (FOB) price: The price of gas delivered by ship to a destination port. LNG prices can be specified on a FOB basis.

Gas supply agreement: A contract between the buyer and seller for the supply of gas.

Henry Hub: Is a major gas hub for spot and futures trading in the United States and acts as the notional point of delivery for gas futures contracts. Henry Hub is based on the physical interconnection of 9 interstate and 4 intrastate pipelines in Louisiana.

Japan Korea Marker (JKM): Is an international benchmark price for LNG spot cargos. It reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.[1]

Liquefaction: The process of liquefying natural gas.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG netback price: An LNG netback price is a measure of an export parity price for gas. It represents the effective price an LNG producer would expect to receive for gas, at a specific reference location, if that gas were converted to LNG and exported. This is done by taking the price payable for LNG and subtracting or 'netting back' costs incurred between the reference location and the location where the LNG is delivered.

LNG strip: A multi-cargo LNG contract with duration typically over the short to medium-term.

LNG train: A liquefied natural gas plant's liquefaction and purification facility.

LNG producer: LNG producers process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets.

Million British Thermal Units (MMBtu): One Thousand Thousand British Thermal Units.

National Balancing Point (NBP): Is a major virtual market place for gas located in the United Kingdom that allows market participants to transfer gas to other participants.

Oil index: An average of regional oil prices calculated over a given day. Examples include Brent and the Japanese Crude Cocktail (JCC).

R^2: The coefficient of determination, which is a measure the 'goodness-of-fit' for linear regression models. This captures the explanatory power of independent variables on a dependent variable.

[1] U.S Department of Energy, *Global LNG Fundamentals*, 2017, https://www.energy.gov/sites/prod/files/2017/10/f37/Global%20LNG%20Fundamentals_0.pdf, viewed 15 March 2021.

Sale and Purchase Agreement: An agreement between the buyer and seller for LNG.

Title Transfer Facility (TTF): Is a major virtual market place for gas located in the Netherlands that allows market participants to transfer gas to other participants.[2]

Wellhead: The location at which gas is injected into the pipeline system.

[2] Gasunie Transport Services, *TTF*, n.d., https://www.gasunietransportservices.nl/en/shippers/products-and-services/ttf, viewed 15 March 2021.

Executive summary

The Australian Competition and Consumer Commission (ACCC) has conducted a review of the LNG netback price series. Based on this review, our draft decision is that publishing additional forward LNG netback prices will improve the series' relevance for domestic buyers seeking longer-term domestic gas supply agreements (GSAs).

ACCC's draft decision

Our draft decision is to:

- continue to publish historical and short-term forward LNG netback prices extending to 2 years based on JKM spot prices
- publish longer-term forward LNG netback prices extending to 5 years based on an oil index.

The ACCC will source from a consultant an estimate of the appropriate percentage, or slope, to apply to oil indexes no less frequently than on an annual basis, to calculate longer-term forward LNG netback prices.

Our draft decision is to maintain our current approach to estimating export costs in calculating LNG netback prices.

Longer-term LNG freight cost estimates will be sourced from a consultant no less frequently than on an annual basis.

We have made the draft decision to deduct only avoidable (marginal) export costs in calculating the LNG netback price series. Consistent with maintaining the opportunity cost approach to calculating LNG netback prices, we will deduct only the costs that are avoided by supplying uncontracted gas to the domestic market. This does not include fixed export costs such as LNG plant capital costs.

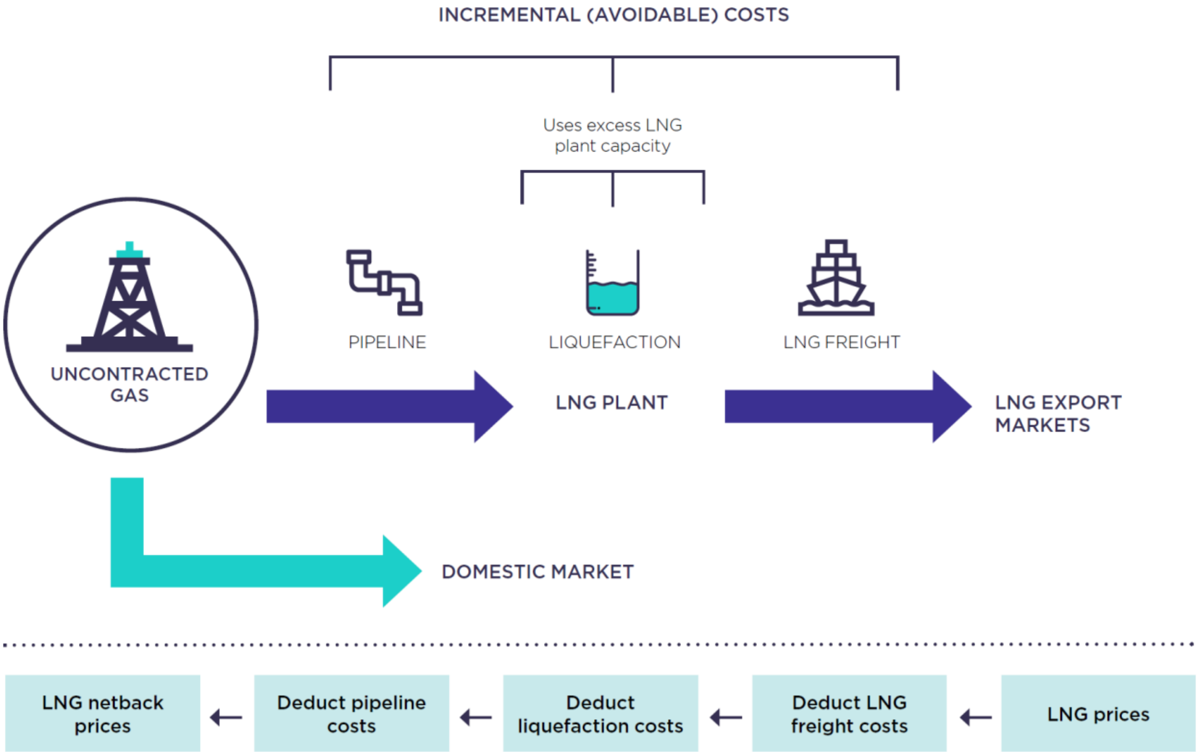
The role of the LNG netback price series

We began publishing the LNG netback price series in 2018 to improve transparency of gas prices in the east coast gas market and to help address information asymmetry and unequal bargaining positions in the market. We are undertaking this review to ensure our methodology for calculating the LNG netback price series remains appropriate.

The development of the Queensland LNG projects linked the east coast gas market to LNG export markets. Our LNG netback price is intended to reflect commercial reality and represents the opportunity cost to LNG producers of supplying uncontracted gas to the domestic market rather than exporting it into international LNG markets (figure 1). It is a measure of the price for uncontracted gas an LNG producer would need to receive from domestic buyers to be indifferent to supplying that gas to the domestic market or overseas markets.

If domestic gas prices fall below LNG netback prices, then LNG producers would no longer be indifferent and will have incentives to sell uncontracted gas overseas, rather than to domestic buyers, up to the level of spare capacity in the LNG plants. Given LNG producers supply approximately 40% of domestic demand, domestic gas prices below LNG netback prices will likely cause a fall in supply to the east coast gas market and place upward pressure on domestic gas prices.

Figure 1: LNG netback price conceptual framework



In a well-functioning market, we would expect LNG producers to supply uncontracted gas to Wallumbilla at prices broadly similar to LNG netback prices.

Under some circumstances, domestic buyers may have to offer LNG producers prices in excess of the LNG netback price. For example, if the LNG producer incurs transport costs in delivering the gas to the buyer, if the LNG netback price is below the LNG producer's marginal cost of production or if the nature of the contract requires the gas producer to take on more risk than if the gas was exported.

Our review and stakeholder consultation

We have consulted with stakeholders extensively in forming our draft decision. Following the release of our issues paper, we received 22 submissions from stakeholders and had an additional 17 meetings to discuss these submissions. Our draft decision is informed by these submissions and stakeholder meetings.

In undertaking this review, we have considered:

- the most appropriate time period, or periods, over which to publish forward LNG netback prices
- the appropriate LNG price or prices to be used as a reference to calculate LNG netback prices, and
- how costs are considered in calculating LNG netback prices.

We will be undertaking further consultation in response to our draft decision. This is set out below.

Expert advice

The ACCC engaged Wood Mackenzie consultancy to provide expert advice on a range of matters to inform our draft decision in the LNG netback price series review. In particular, we requested information on:

- how future LNG market developments may impact, directly or indirectly, the east coast gas market
- the relevance of international LNG prices or price markers to domestic gas pricing in the east coast gas market, and the extent of their relevance
- approaches to estimating future shipping costs
- long-run vs short-run cost factors in calculating LNG netback prices, and
- other factors relevant to calculating an LNG netback price.

Wood Mackenzie its preliminary report to the ACCC on 24 June 2021, which is available on the ACCC website. Wood Mackenzie will provide its final report to the ACCC in September 2021.

The ACCC seeks feedback on Wood Mackenzie's preliminary report findings.

ACCC Draft Decision

Relevant time periods for forward LNG netback price series should reflect domestic gas contract time periods

Publishing historical and short-term 2-year forward LNG netback prices based on Asian spot prices remains appropriate

Our draft decision is to continue publishing historical and short-term forward LNG netback prices based on Asian spot prices.

Historical and short-term forward LNG netback prices continue to be relevant for domestic gas buyers. Queensland LNG plants continue to have excess liquefaction capacity; this means that domestic producers will, for the foreseeable future, be able to access LNG export markets as an alternative to domestic supply.

As a result, domestic gas pricing continues to be influenced by Asian LNG spot prices. The majority of LNG exported from Queensland is exported to northeast Asia and Asian LNG spot prices, on a netback basis, reflect the opportunity cost to LNG producers of supplying uncontracted gas into the domestic market. (That is, they reflect the revenue that LNG exporters give up when they supply gas to the domestic market).

This is consistent with our findings from examining internal documents of gas suppliers about their pricing strategies, set out in detail in our Gas Inquiry 2017–2025 interim reports for January 2021 and July 2021 (soon to be released).

By measuring the price LNG producers can expect to receive for exporting uncontracted gas into Asian LNG spot markets, our LNG netback price series improves transparency around current and future pricing trends in the domestic market and improves information symmetry for domestic gas buyers in their negotiations with LNG producers.

A longer-term forward LNG netback price series will assist domestic gas buyers

Our draft decision is to extend the LNG netback price series by including additional forward LNG netback prices out to 5 years. Our examination of gas supplier pricing strategy documents, published in our Gas Inquiry 2017–2025 interim reports for January 2021 and July 2021 (soon to be released), found that LNG producers regularly consider short to medium-term multi-cargo LNG contract prices in pricing multi-year domestic GSAs for uncontracted gas.

Our existing forward LNG netback prices have diminished relevance to domestic gas buyers that routinely consider and enter into GSAs longer than the current 2-year forward period.

An extended LNG netback price series will help inform negotiations between suppliers and C&I users for longer-term domestic GSAs. As such, our draft decision is to publish additional forward LNG netback prices that extend to 5 years.

Appropriate price markers for 2-year and longer-term forward LNG netback prices

JKM is the most appropriate measure of Asian LNG spot prices for a 2-year forward period

Our draft decision is to continue using JKM to calculate historical and short-term forward LNG netback prices. JKM is the most commonly used measure of Asian LNG spot prices and reflects LNG supply and demand fundamentals in Asia, which remains the key export destination for LNG from Queensland.

Current 2-year forward LNG netback prices based on JKM remain relevant for domestic gas buyers that consider and enter into GSAs for periods of less than 2 years.

However, there are limitations in using JKM for forward periods beyond 2 years. While JKM has sufficient liquidity to be a reliable reference in the short term, this liquidity drops off after 2 years and JKM is not currently liquid enough to be used to calculate longer-term forward LNG netback prices.

Some stakeholders recommend the ACCC use Henry Hub prices as a starting point for calculating LNG netback prices. We do not consider this to be appropriate. Henry Hub prices reflect the supply-demand fundamentals of the US domestic gas market and these prices currently have limited influence on Asian LNG pricing. LNG that has been bought at Henry Hub prices and supplied into Asia is already captured in Asian price assessments such as JKM. Further, as domestic LNG producers do not export gas to the US, Henry Hub prices are an indirect and imperfect measure of the opportunity cost of supplying gas to the domestic market.

Henry Hub prices may have greater influence on Asian LNG prices as US LNG export volumes into Asia grow. However, it is not clear when this may occur or how much influence it may have. To the extent that Henry Hub influences Asian LNG markets, Henry Hub prices will be reflected in our 2-year forward LNG netback price series through our use of the JKM.

Oil-linked indexes are relevant for longer-term forward LNG netback prices

Our draft decision, on balance, is to publish longer-term forward LNG netback prices using an oil index. The majority of short to medium-term LNG contracts sold into northeast Asia are priced using some form of oil-linkage. Oil futures markets are also deep, liquid and highly transparent.

A key challenge in using an oil-linked index as a measure for calculating forward LNG netback prices is determining the appropriate percentage (or 'slope') of the oil price that determines the LNG price.

There is no comprehensive publicly listed record of actual or current LNG contracts or price formulae. Stakeholders currently rely on market assessments, performed by analysts and research companies, to determine appropriate slopes. Oil-linked slopes can also differ between LNG contracts depending on a range of factors such as flexibility in delivery terms, volumes and seasonality. They can also change over time as LNG market conditions change.

Publishing longer-term forward LNG netback prices will add transparency to the market and address an existing information asymmetry between C&I users and those suppliers who already consider oil-linked LNG prices when forming views about longer-term domestic prices.

However, a potential risk of publishing longer-term forward LNG netback prices is that these prices could become a de facto market price floor, particularly in periods where oil-linked LNG netback prices are higher than those based on JKM.

This risk is largely caused by the lack of certainty and transparency around some key inputs used in calculating the longer-term forward LNG netback prices, in particular the slope. As a result, there is a risk that the ACCC's long-term forward LNG price series may differ from the actual commercial alternatives available to the LNG producers when deciding whether to enter long-term domestic GSAs. This is likely to be of particular concern if the ACCC's long-term forward LNG prices are above the prices that LNG producers could actually achieve in exporting gas. For example, this could occur if the ACCC publishes longer-term forward LNG netback prices based on a slope that is above the slope underpinning longer-term export contracts that are available to LNG producers. In such a case, there is a risk that the LNG producers will treat the ACCC's LNG netback prices as price floor in negotiations with domestic buyers, resulting in domestic gas prices that are higher than they otherwise would have been the case.

It is not clear how material these risks are, or whether they would be outweighed by the benefits of additional transparency. Our preliminary view is that, on balance, publishing longer-term forward LNG netback prices, using an oil index, is likely to have a net benefit for the east coast gas market by reducing a key information asymmetry between producers and C&I users when negotiating long-term contracts.

If the ACCC decides to publish longer-term LNG netback prices, we will source an estimate of the appropriate slope to use from a consultant no less frequently than on an annual basis.

Given these risks, we seek feedback on whether the ACCC should publish longer-term forward LNG netback prices, the potential materiality of risks involved and on our proposed approach to doing so.

How costs are considered in calculating LNG netback prices

Deducting only avoidable export costs remains appropriate

Our draft decision is that deducting only avoidable (marginal) export costs in calculating the LNG netback price series remains appropriate.

Consistent with our opportunity cost approach to calculating LNG netback prices, the ACCC deducts only the costs an LNG producer incurs when supplying uncontracted gas to Asian export markets, and which are avoided if the LNG producer instead chooses to supply the uncontracted gas to the domestic market.

These costs include:

- the LNG freight costs of transporting LNG from Gladstone to the destination port in Asia
- liquefaction costs associated with converting gas to LNG
- pipeline transportation costs to transport gas from the wellhead to the LNG facility in Gladstone.

These costs do not include any that are fixed or have already been incurred (sunk costs) as these costs are not incurred again to export uncontracted gas and cannot be avoided by supplying uncontracted gas to the domestic market. This includes the capital costs of developing the Queensland LNG plants. See also figure 1.

This approach ensures an LNG producer is indifferent to supplying uncontracted gas to the domestic market or to LNG export markets and reflects the commercial realities of the east coast gas market.

Our approaches to estimating export costs

Our draft decision is to maintain our current approach to:

- deducting pipeline transport costs
- deducting liquefaction costs
- converting Gladstone FOB prices from $USD/MMBtu to $AUD/GJ.

We will update cost estimates when the ACCC has finalised its decision on how export costs should be estimated (following the end of the review).

We consider our current approach to estimating historical LNG freight costs remains appropriate. However, our current approach to estimating LNG freight costs is limited to a forward period of 2 years.

An alternative source of LNG freight cost estimates is needed to publish longer-term forward LNG netback prices. While there are several possible alternatives, our draft decision is to source estimates of longer-term LNG freight costs from a consultant no less frequently than on an annual basis. We seek feedback on this decision and any alternatives sources of longer-term LNG freight cost estimates (out to 5 years).

A further review will be required in 2024

Our proposed approaches to calculating the historical, short-term forward and longer-term forward LNG netback price series appropriately reflect current supply and demand factors in both the east coast gas market and LNG export markets. However, these markets are dynamic and future developments may have implications for how east coast gas producers consider the alternatives to supplying the domestic market (in the future).

The development of an LNG import terminal on the east coast is likely to influence gas prices in the east coast gas market and add to the need for a holistic evaluation of which benchmark price or prices are most appropriate for the domestic market.

Our draft decision is to conduct another public review of our LNG netback price series in 2024, to ensure it remains fit for purpose.

Stakeholder views are now sought on our draft decision

The ACCC seeks stakeholder views on our proposed approach to calculating the LNG netback price series outlined in this draft decision.

Feedback is sought on the following:

The length of the forward LNG netback price series

1. Is the ACCC's draft decision to continue publishing a 2-year forward LNG netback price series appropriate? Should the ACCC continue to publish a 2-year forward LNG netback price series?
2. Is the ACCC's draft decision to publish additional longer-term forward LNG netback prices appropriate? Should the ACCC publish additional longer-term forward LNG netback prices?
3. Over what length of time should the ACCC publish additional longer-term forward LNG netback prices (such as 3 or 5 years)?
4. What other issues should be considered when publishing longer-term forward LNG netback prices.

LNG price markers to calculate the LNG netback price series

5. Is the ACCC's draft decision to continue using JKM to publish historical and short-term forward LNG netback prices appropriate?
6. What is the minimum level of liquidity needed in JKM futures to extend the current forward LNG netback price beyond 2 years?
7. Is the ACCC's draft decision to use prices in medium-term oil-linked LNG contracts to calculate additional longer-term forward LNG netback prices appropriate? Should the ACCC publish additional longer-term forward LNG netback prices based on oil-indexes?
8. Is the ACCC's draft decision to use consultant estimates of an appropriate percentage, or slope, of the oil price to calculate longer-term forward LNG netback prices appropriate?
9. What other issues should be considered in calculating shorter and longer-term forward LNG netback prices?

Export costs deducted to calculate the LNG netback price series

10. Is the ACCC's draft decision to use the current approach to calculating forward LNG freight costs, for period up to 24 months, appropriate? Should the ACCC use an alternative approach?
11. Is the ACCC's draft decision to use consultant estimates of longer-term forward LNG freight costs appropriate? Alternatively, should the ACCC
    (a) determine an indicative daily charter rate based on an estimate of the long-run marginal costs (LRMC) of building new LNG freight vessels
    (b) estimate the extended forward LNG freight cost based on an average of the historical or short-term forward LNG freight costs, and how should the average period be determined
    (c) estimate the extended forward LNG freight cost as a percentage of the extended forward LNG netback price, and how should that percentage amount be determined?
12. What other issues should be considered in estimating future LNG freight costs?
13. Is the ACCC's draft decision to use its current approach to deducting liquefaction costs to calculate additional longer-term forward LNG netback prices appropriate?
14. What other issues should be considered when estimating and deducting LNG liquefaction costs?
15. Is the ACCC's draft decision to use its current approach to deducting pipeline transportation costs to calculate additional longer-term forward LNG netback prices appropriate?
16. What other issues should be considered when deducting pipeline transportation costs?

Reviewing the LNG netback price series in 2024

17. Is the ACCC's draft decision to undertake another review of the LNG netback price series in 2024 appropriate?

Feedback is also sought on the preliminary report provided by Wood Mackenzie published on the inquiry webpage.

Submissions are due by 5pm AEST 30 July 2021 to LNGnetbackreview@accc.gov.au.

The ACCC will convene a stakeholder forum on 20 July 2021. The forum will provide an opportunity for stakeholders to discuss the views published in this draft decision paper and in submissions to our review. The forum is open to any interested stakeholders. If you wish to attend, please email LNGnetbackreview@accc.gov.au.

Following consideration of stakeholder views, we will publish our final decision by the end of September 2021, as requested by the Australian Government.

1. Introduction

The Australian Competition and Consumer Commission (ACCC) is undertaking a review of the LNG netback price series, which we publish regularly on the ACCC website, as part of the ongoing inquiry into the east coast gas market (the Inquiry).[3]

In 2020, the Australian Government requested that the ACCC review its LNG netback price series by the end of September 2021. The request was made as part of a broader range of government announced measures that seek to increase gas supply, increase efficiencies in gas transportation and improve the negotiating power of gas consumers in the east coast gas market.[4]

It is appropriate to undertake a public review of the LNG netback price series now. There have been significant changes in LNG markets due to growing supply and increased trade in LNG spot markets. Findings from the ACCC's review of pricing strategy documents obtained from east coast gas suppliers indicate that longer-term LNG contract prices also influence domestic gas market prices.

This review is considering a range of matters related to calculating the LNG netback price series, including:

- the most appropriate time period, or periods, over which to publish forward LNG netback prices. The ACCC currently publishes forward LNG netback prices over a 2-year period
- the choice of LNG price used as a reference to calculate the LNG netback price series. The review is considering the merits of different LNG and gas price markers, based on their relevance to the east coast gas market
- how LNG liquefaction cost and pipeline transportation costs are considered in calculating the LNG netback price series.

Some submissions referenced a number of proposed LNG import terminals for the east coast of Australia.[5] We will consider the development of an import parity price once it becomes clearer if an import terminal will commence operation on the east coast and the arrangements that will apply to its commercial operations.

1.1. Our approach to the review

In March 2021, the ACCC released an issues paper seeking stakeholder feedback on a range of issues, such as the length of the forward LNG netback price series and the LNG netback price methodology. Submissions made in response to this issues paper informed our draft decision outlined in this report. Submissions made to the issues paper are available on the ACCC website.

In April 2021, we met with a number of stakeholders to discuss their submissions and feedback on the issues paper. In addition, the ACCC engaged Wood Mackenzie consultancy to provide expert advice on a range of matters to inform our draft decision on the LNG netback price series methodology. Wood Mackenzie's preliminary report is available on the ACCC website.

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3 ACCC, *Gas Inquiry 2017-2025 webpage*, March 2021, https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025, viewed 15 March 2021.

4 Prime Minister of Australia, Media Release, *Gas-fired Recovery*, 15 September 2020.

5 APLNG, Submission to the issues paper, April 2021; CME, Submission to the issues paper, April 2021; Esso, Submission to the issues paper, April 2021; GLNG Operations, Submission to the issues paper, April 2021; Senex, Submission to the issues paper, April 2021; Shell, Submission to the issues paper, April 2021; S&P Global Platts, Submission to the issues paper, April 2021.

This paper presents our draft decision and findings made in undertaking this review. We will undertake another round of stakeholder consultation in response to this draft decision paper, and consider the feedback in reaching our final decision.

We will convene a stakeholder forum on 20 July 2021. The forum will provide an opportunity for stakeholders to discuss the views published in this draft decision paper and in submissions to our review. The forum is open to any interested stakeholders. If you wish to attend, please email LNGnetbackreview@accc.gov.au.

We will publish our final decision and provide a copy to Government on 30 September 2021, and implement any changes to the LNG netback price series that are necessary following the publication of our final decision.

1.2. Next steps

The ACCC seeks submissions on the draft decision and issues raised in this draft decision paper. In particular, we seek feedback on:

- a number of questions, which are highlighted throughout the report (see appendix A)
- the preliminary report provided by Wood Mackenzie and published on the ACCC website.

Interested parties may also wish to respond to views and arguments put by others in submissions to this review.

1.2.1. How to participate

Stakeholders are invited to participate in the review of the LNG netback price series.

Interested parties may provide written submissions to the ACCC in response to this draft position paper (feedback is requested by 30 July 2021).

Interested parties can also request a meeting with the ACCC to discuss issues raised in their submissions using the contact details set out below.

1.2.2. Guidelines for making a written submission

Please provide your submission in electronic form, either in PDF or Microsoft Word format, which allows the submission to be text searched.

Please provide examples, evidence and data (with sources) where available.

Submissions to this issues paper are due by 5pm AEST on 30 July 2021.

Submissions should be emailed to LNGnetbackreview@accc.gov.au.

1.2.3. Treatment of confidential information

The review is a public process and written submissions will be made available on the ACCC website.

The *Competition and Consumer Act 2010* allows parties that provide written submissions to the Inquiry to make claims for confidentiality in limited circumstances.

The ACCC has published a Confidentiality Guideline which sets out the process parties should follow when submitting confidential information to communications inquiries commenced by the ACCC. The Guideline describes the ACCC’s legal obligations with respect to confidential information, the process for submitting confidential information and how the ACCC will treat confidential information provided in submissions. A copy of the Guideline can be downloaded from website.

Where a party provides a confidential submission it must clearly identify the specific information over which it claims confidentiality and state the basis on which the claim is made.

At the time of providing a confidential submission a party must also provide a public version of the submission that redacts the confidential material so that it appears as blackened text that cannot be viewed by a reader. For example, the text should appears as:

> **The ACCC's draft decision is to publish a 2-year LNG netback price series, on the basis that [redacted] has stated that [redacted].**

The ACCC will post redacted public submissions on its website.

1.2.4. ACCC contacts

To make a submission or request a meeting, please email the ACCC at LNGnetbackreview@accc.gov.au.

If you would like to ask a question about the review, please contact:

Joshua Runciman

Joshua.Runciman@accc.gov.au

03 9290 6959

Brendan Staun

Brendan.Staun@accc.gov.au

02 9230 9149

2. The ACCC's current LNG netback price series

The ACCC began publishing the current LNG netback price series in 2018 to improve price transparency in the east coast gas market. This chapter provides an overview of LNG netback prices and their role in the domestic market.

2.1. The relevance of LNG prices to the east coast gas market

The east coast gas market emerged in the 1960s when a number of gas producers discovered and commercialised significant reserves located in the Gippsland Basin in offshore Victoria, and in the Cooper Basin in northern South Australia and southwest Queensland. These reserves consisted of low-cost conventional gas fields, which enabled the development of a stable and long-term gas market on the east coast.[6]

Until the 2000s, the Gippsland and Cooper basins were the major gas producing regions on the east coast. While production from the Cooper Basin began to decline in the early 2000s, both basins remained key suppliers to the domestic market for all of the 2000s and most of the 2010s.[7]

Commercial production of Coal Seam Gas (CSG), also referred to as coal bed methane, did not occur in Australia until the 1990s, with the first exploration and commercial production of CSG in Queensland occurring in 1996.[8] Queensland gas production began to ramp up in the 2000s, in part due to supportive government policies, which coincided with the discovery of significant CSG reserves in the Surat and Bowen Basins.

The discovery of these reserves led to the development of 3 LNG projects on the east coast of Australia.

To underpin the substantial financial investments needed to build the LNG plants, which were in excess of AUD$20 billion per plant, each of the LNG projects entered into long-term (most for 20 years) LNG Sale and Purchase Agreements (SPAs) with 'foundation' buyers in Asia.[9] These SPAs commit the Queensland LNG projects to supply a specified quantity of LNG over the life of the contract. Because of this, a substantial portion of the LNG producers' reserves are already contracted.

Some of the LNG projects produce gas beyond that required to meet their long-term LNG SPAs (and their long-term domestic contractual commitments). In practice, this means that these LNG producers have uncontracted gas that has not yet been committed to domestic buyers or to international LNG buyers.

The development of Queensland's three LNG projects has connected the east coast gas market to international LNG markets, which has influenced developments in the east coast gas market since. As noted in our 2015 East Coast Gas Inquiry, the commencement of the LNG projects '… triggered significant structural changes in the east coast gas market.'[10]

Prior to the development of the Queensland LNG projects, gas produced in the domestic market by upstream producers was able to be sold only in the domestic market, either to

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6 Bureau of Resources and Energy Economics, *Gas Market Report*, November 2014, https://www.aph.gov.au/~/media/Committees/economics_ctte/estimates/add_1617/Industry/answers/AI-87_Whish-Wilson_Attachment4.pdf, viewed 29 June 2021.

7 ibid; ACCC, Gas Inquiry 2017-2025 interim report, January 2021.

8 ibid.

9 GIIGNL, *Annual Report 2021*, 4 May 2021, https://giignl.org/system/files/giignl_2021_annual_report_may4.pdf, viewed 29 June 2021.

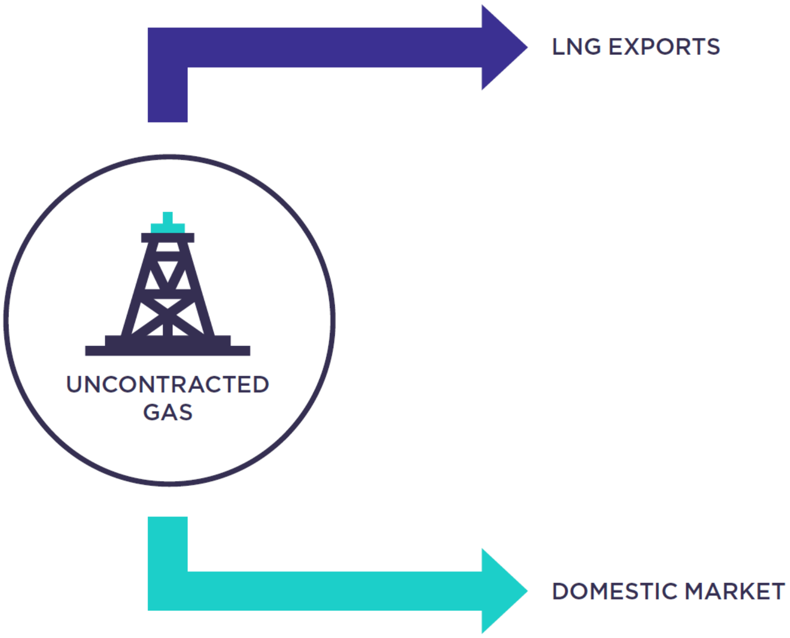
10 ACCC, Report, *Inquiry into the east coast gas market*, April 2016, p. 24.

retailers, gas powered generators or to commercial and industrial users. Because of this, gas suppliers on the east coast only had one option, which was to supply gas to the domestic market at prevailing market prices (which were significantly lower than contemporary domestic gas price levels).

The development of the LNG projects has provided all gas producers on the east coast (and the Northern Territory) the option of supplying any uncontracted gas to:

- export markets, in the form of LNG
- the domestic market (figure 2.1).

Figure 2.1: Domestic producers have access to LNG export markets



In practice, the option to supply export markets is more readily available to the LNG producers as they own and operate the LNG plants. We have observed LNG producers selling uncontracted gas into LNG spot markets over the course of the current inquiry.

Non-LNG producers may also be able to access LNG export markets, however, by entering into agreements with the Queensland LNG producers. This could involve domestic gas suppliers:

- selling gas directly to LNG producers on a third-party basis, at prices influenced by prices in export markets, which an LNG producer would then liquefy and export
- entering into a 'tolling' arrangement with an LNG producer to access unutilised LNG plant liquefaction capacity, whereby an LNG producer would charge a toll to liquefy gas on behalf of another gas supplier, with that supplier then selling the LNG into export markets.

We have also observed that some non-LNG producers on the east coast view selling to the LNG producers as an alternative to supplying the domestic market.[11] In the 2015 East Coast Gas Inquiry, we also observed that the Queensland LNG projects have economic incentives to purchase additional gas to maximise LNG production, provided it is profitable for them to sell that gas into overseas markets.

[11] ACCC, Gas Inquiry 2017-2025 interim report, January 2021.

Our recent examination of the pricing strategies of key domestic suppliers confirms that LNG producers, and other gas producers, on the east coast consider LNG netback prices when forming views about prices in the domestic market. In particular, producers generally view JKM as a relevant reference price for shorter-term GSAs up to a term of 2 years, with some producers considering oil-linked LNG strips as being relevant beyond 2 years (chapter 4).

LNG producers will continue to be able to sell uncontracted gas into export markets only if the Queensland LNG plants continue to have unutilised excess LNG capacity (in aggregate) and they are able to recover their marginal costs of producing this uncontracted gas. As discussed in chapter 5, in the absence of major new gas discoveries, the Queensland LNG plants will continue to have unutilised liquefaction capacity, meaning LNG producers will continue to have an alternative to supplying the domestic market.

2.2. What is an LNG netback price?

The development of the Queensland LNG projects connected the east coast gas market to international LNG markets. LNG producers who supply uncontracted gas into the domestic market forego the opportunity to supply that gas into LNG export markets. This means that there is an opportunity cost associated with supplying the domestic market.

An LNG netback price represents the opportunity cost to LNG producers of supplying uncontracted gas to the domestic market rather than exporting into international LNG markets. It is the price for uncontracted gas an LNG producer will expect to receive from domestic buyers to be indifferent to supplying that gas to the domestic market or overseas markets.

LNG netback prices reflect the commercial options available to LNG producers for their uncontracted gas. They can sell it domestically, into international markets or, where feasible, divert it into storage or delay production. Because of this, an LNG netback price is inherently calculated from the perspective of a gas seller, LNG producers in this case, rather than that of a gas buyer.

By publishing LNG netback prices, the ACCC is providing information to the market on the commercial realities faced by LNG producers when supplying the domestic market. The ACCC is not providing a view on what level of gas pricing is ‘fair’ to either sellers or buyers, or trying to provide a ‘bottom up’ reference price that applies a margin to gas production costs.

An LNG netback price also represents the maximum price an LNG producer will be willing to purchase gas from non-LNG producers (other than if the LNG producer is short of gas required to meet contractual obligations), as it will not be able to export gas purchased from non-LNG producers above this price for a profit.

The LNG netback price is an important benchmark because if domestic gas prices fall below LNG netback prices, then LNG producers will have the incentive to sell uncontracted gas overseas rather than to domestic buyers. Given LNG producers supply approximately 40% of domestic demand,[12] such a shift will likely cause a shortage in the east coast gas market and place upward pressure on domestic gas prices.

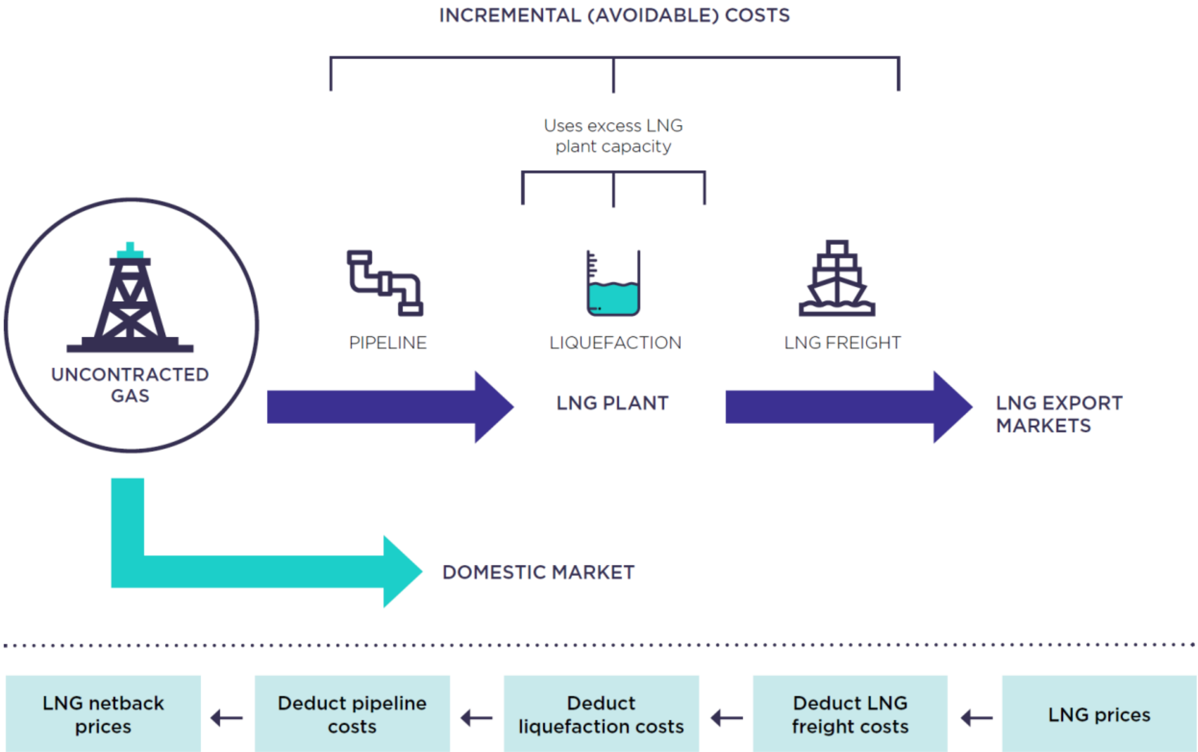
If LNG netback prices and domestic prices are below the marginal costs of production, gas producers may also have incentives to store uncontracted gas or delay gas production.

[12] ACCC, Gas Inquiry 2017-2025 interim report, January 2021.

We calculate LNG netback prices by taking the price that LNG producers will expect to receive for supplying uncontracted gas to overseas buyers and deducting any costs that are incurred to export that uncontracted gas (figure 2.2). These costs include:

- LNG freight costs of transporting LNG from Gladstone to the destination port in northeast Asia
- Liquefaction costs associated with converting gas to LNG
- Pipeline transportation costs to transport gas from the wellhead to the LNG facility in Queensland.

Figure 2.2: Conceptual framework for LNG netback prices



In deciding which costs to deduct, we consider only the costs the LNG producer incurs when supplying uncontracted gas to Asian export markets, and which are avoided if the LNG producer instead chooses to supply the uncontracted gas to the domestic market. This is because LNG producers will consider only these costs when deciding whether to supply uncontracted gas to LNG export markets or the domestic market.

We do not deduct any costs that cannot be avoided by LNG producers because these costs are incurred by gas producers regardless of where the uncontracted gas is sold. This includes the costs of extracting the gas at the wellhead and the capital costs incurred in developing the pipeline and LNG plants. This is discussed further in chapter 5.

Deducting non-avoidable costs would mean the LNG netback price series would no longer represent the price at which domestic producers would be indifferent between supplying the domestic market and export markets.

2.3. The role of LNG netback prices

The ACCC developed and began publishing the LNG netback price series to improve transparency around current and future pricing trends in the domestic market, and to improve the relative bargaining positions of C&I users and other gas buyers.

Importantly, the LNG netback price represents market expectations at a point in time for the various inputs used in its calculation. Forward LNG netback prices are not the ACCC's expectation or forecast of what LNG netback prices should or will be at any particular point in time.

The ACCC has reported on a number of occasions that contemporary gas prices are significantly higher than historical prices. The ACCC also previously observed that the development of the LNG projects had significant structural impacts on the east coast gas market.

By introducing an option to export LNG, the LNG projects linked the domestic market to LNG markets.[13] The development of the LNG projects, along with the impact of low oil prices on investment and moratoria on exploration, also created significant uncertainty about the level of supply relative to demand in the east coast gas market, which in turn contributed to uncertainty about gas prices at a time when prices were increasing significantly.

When the current Gas Inquiry began in 2017, C&I users expressed concerns about the lack of information on east coast wholesale gas prices available to them to assist them in understanding the drivers of domestic gas prices and what prices were likely to be in the future. Because of this, C&I users generally had differing views on how LNG prices might influence domestic gas prices.

The ACCC noted in the April 2018 report that the lack of an 'indicative' reference price in the east coast gas market was a key problem for C&I users. Most gas on the east coast is traded under long-term confidential, bilateral contracts.[14] As a result, information on gas pricing is not broadly available with most C&I users having very limited, or no, insight into pricing being agreed in the market.

The ACCC also found, in the 2015 East Coast Gas Inquiry, that gas suppliers had greater and more reliable information on recent gas prices to inform their negotiations for gas supply with C&I users (relative to the level of information that individual C&I users had). This is because gas suppliers tend to engage in negotiations more frequently than C&I users. The ACCC's analysis of data on offers made by gas suppliers suggests that this information asymmetry has persisted.

The lack of information on gas prices and information asymmetry can mean gas buyers are disadvantaged in their negotiations with gas suppliers. This can impair competitive bargaining and favour large incumbent gas suppliers.[15]

Regularly publishing LNG netback prices improves price discovery in the east coast gas market by providing up-to-date information to all market participants on a key factor that influences domestic gas prices. Further, major gas suppliers, including the LNG producers, already have access to, and consider, information on LNG prices.[16] By publishing LNG netback prices, we are making this information available to more market participants.

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13 ACCC, Report, *Inquiry into the east coast gas market*, April 2016.

14 STTMs are short-term trading markets located in Sydney, Adelaide and Brisbane.

15 ACCC, Gas Inquiry 2017-2020 interim report, April 2018.

16 ACCC, Gas Inquiry 2017-2025 interim report, January 2021.

Importantly, LNG netback prices are not the sole factor influencing domestic gas prices, and contract terms and conditions can also influence GSA prices (section 2.3.1).

Our LNG netback price series provides an indicative reference price for gas in the east coast gas market. It reflects an LNG producer's point of indifference between supplying the domestic market or export markets, which C&I users can compare against contemporaneous gas prices being offered or agreed. It also provides information to market participants on historical and seasonal pricing trends.

LNG netback prices may act as a price floor for domestic gas prices in circumstances where there is excess liquefaction capacity in the Queensland LNG plants and where uncontracted gas from the LNG producers is necessary to avoid domestic supply shortfalls (that is, the LNG producers are the marginal suppliers to the domestic market). However, in a well-functioning market, we would expect domestic prices to be broadly similar to LNG netback prices.

2.3.1. The relevance of other factors to domestic prices

Factors other than LNG netback prices may also influence gas prices offered in the domestic market.

In submissions, Shell, GLNG and Origin note factors that can influence domestic prices include contract duration and terms, retailer margins, transportation costs and gas production costs.

The following factors may, to some extent, influence the prices offered by domestic suppliers for longer-term GSAs.

- **Cost of transportation:** if the supplier is required to transport gas to the buyer's location, the delivered price of gas will reflect both the gas commodity charge (the price of the gas itself) and the cost of transporting the gas to the buyer's location. The cost of transportation will therefore directly affect the price payable for gas at the buyer's location. The commodity charge itself may also be affected by transportation costs in the southern states. However, that transportation costs are not relevant when gas is offered for supply at Wallumbilla.
- **Cost of production:** production costs would, in most circumstances, set the floor price in negotiations between gas producers and gas buyers, particularly for longer-term gas offers. This is because gas producers have some ability to defer or delay production. There may, however, be some periods where suppliers sell at or below costs of production if they are not able to ramp down gas production in response to low prices.
- **Non-price terms and conditions:** the particular characteristics of a user's gas requirements can influence the price a supplier may be willing to offer that user. Specifically, non-price terms and conditions in GSAs, such as take-or-pay levels, daily swing (load factor) allowances, transportation requirements, GSA quantity and duration can affect the costs and risks associated with supplying a particular user. The supplier may charge a higher price to recoup costs or reward risk taken.

  However, costs and risks associated with an individual GSA can be smoothed out and reduced across a portfolio of GSAs. Consequentially, the costs and risks taken on by a supplier when entering a marginal domestic GSA may not be as high when considered in the context of the supplier's entire portfolio.

  Further, it is not clear whether non-price terms and conditions add materially to the costs faced by gas suppliers, at least in the majority of cases.

- **Retailer costs and margins:** prices charged by retailers under GSAs are generally higher than those charged by producers. There are factors that are specific to gas supply by retailers that may influence retailers' price offers, including costs incurred by retailers associated with transportation and demand variations, and retailer margins.

  Costs associated with managing demand variations (gas shaping) can vary depending on the flexibility of the GSA. For example, under a GSA with a high load factor, the user may require a significant quantity above the average daily quantity on a particular day. This may result in a shortfall in the retailer's portfolio on that day, which would need to be filled using gas either purchased from domestic short-term markets or drawn from storage. The expected cost to the retailer of addressing these daily variations over the life of the GSA will determine the additional costs that will be passed on to the user.

  Similarly, a higher load factor may result in higher transportation costs since the retailer will need to ensure that there is pipeline capacity available to satisfy additional demand beyond the average daily quantity.

- **Domestic short-term trading markets:** prices in GSAs might be explicitly linked to prices in one or more of the domestic short-term markets. There may also be circumstances where retailers sell gas to users before they purchase it from producers, conferring a price risk onto the retailer. Depending on the availability of gas in the market, the retailer may need to rely on domestic short-term trading markets to secure sufficient gas to meet their contractual commitments to the C&I user. In these circumstances, the retailer may factor in this risk into the GSA price it offers to the C&I user.

  Finally, sourcing gas from domestic short-term markets may be an alternative to entering into GSAs. While the majority of gas buyers in the east coast gas market continue to rely on long-term GSAs to meet their gas requirements, a number of C&I users are now using, or investigating the use of, domestic short-term trading markets to either supplement GSAs or to source their entire gas requirements. If these markets were to become liquid such that a greater number of C&I users could rely on them for their ongoing gas needs, the prices in the domestic short-term markets would have a greater influence on the prices agreed under GSAs.

- **Electricity prices:** recent retirements of coal-fired generators has increased reliance on other forms of generation, including GPG, particularly during peak demand periods. When electricity demand is high, GPG is often the marginal generator and therefore sets the wholesale electricity price.

2.4. Calculating LNG netback prices

The ACCC calculates LNG netback prices by subtracting, or netting back, costs to liquefy and transport LNG from a relevant LNG price. Figure 2.3 presents a stylised example of how the ACCC calculates LNG netback prices.

Figure 2.3: Stylised example for calculating LNG netback prices

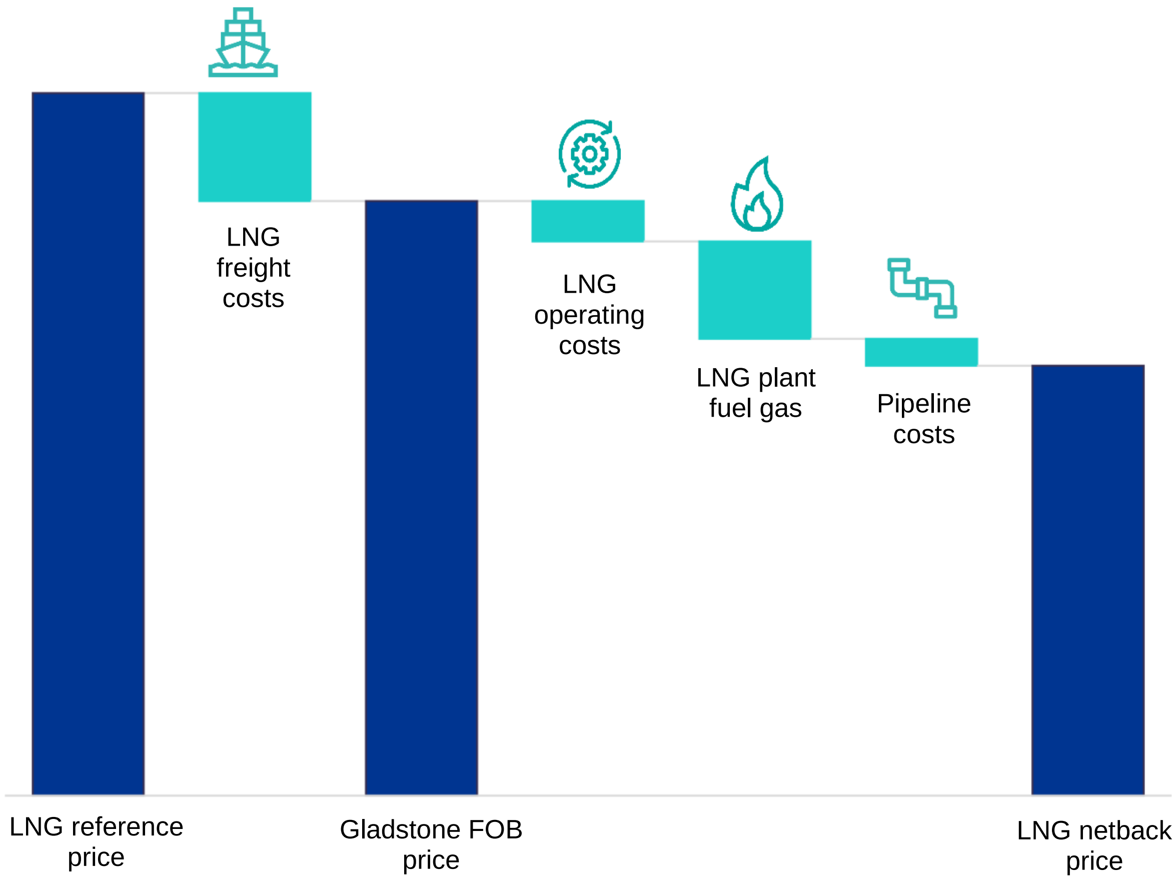

Figure 2.3 shows the key steps involved in calculating the current LNG netback price series, which for shorter-term LNG netback prices are:

1. Start with an LNG price or reference price – the ACCC currently uses and proposes to continue to use Asian LNG spot prices as a shorter-term reference LNG price
2. Subtract LNG freight costs – the ACCC currently uses and proposes to continue to use freight cost estimates for transport of LNG from Gladstone to Tokyo
3. Convert to A$/GJ – the ACCC currently uses contemporary exchange rate data and a GJ to MMBtu conversion ratio of 1:1.055
4. Subtract LNG plant (marginal) costs and LNG plant fuel gas
5. Adjust for pipeline transportation costs from the wellhead to Gladstone and Wallumbilla.

The ACCC's LNG netback price series is netted back to Wallumbilla because this is the pipeline interconnection point that links the LNG producers' gas production facilities to the Australian domestic market.

The ACCC's approach to calculating LNG netback prices is discussed in further detail in the following sections.

2.4.1. LNG reference prices

The starting point for calculating an LNG netback price is a relevant LNG price. The ACCC currently uses the Japan Korea Marker (JKM) to calculate short-term LNG netback prices, with forward prices published over a 2-year forward period. The ACCC uses JKM as it is a widely accepted measure of Asian LNG spot prices and the vast majority of LNG exports from the Australian east coast go to Asia.

In practice, there is a range of LNG prices that the ACCC could use to calculate LNG netback prices, including LNG spot prices and prices under short, medium or long-term LNG contracts. Given LNG contracts are often oil-linked, there may be times where an oil-linked LNG reference price is appropriate.

When the ACCC developed the current LNG netback price series, we expected that the LNG producers would, in aggregate, produce quantities of gas in excess of the quantities required to satisfy their long-term LNG contractual obligations, with this excess likely to be sold into the Asian LNG spot market if it was not used for domestic supply.[17] We have since observed the Queensland LNG producers selling uncontracted gas into Asian LNG spot markets.

As such, the ACCC currently uses Asian LNG spot prices as a reference price for the LNG netback price series.

The ACCC publishes an LNG netback price series using information derived from both historical Asian LNG spot prices, as well as market expectations of future Asian LNG spot prices.

- **Historical LNG netback prices** are based on the Japan Korea Marker (JKM) as assessed daily by S&P Global Platts ('Platts'). JKM represents the price assessment for physical LNG spot cargoes delivered ex-ship into northeast Asia. Price information is obtained from market participants with priority given to bids, offers and settled transactions made through Platts's daily Market on Close process, and represents firm offers and bids for deliveries in a given month.[18]
- **Forward LNG netback prices** are based on JKM futures contracts that are quoted by the International Continental Exchange (ICE), as at the time of publication, as a measure of market expectations of future Asian LNG spot prices for a cargo of LNG, for delivery in a specified future month. These are cash-settled futures based on Platts's JKM price assessments for a given calendar month, and are traded in increments of 10,000 MMBtu. ICE JKM futures prices are settled and published daily, and are determined by ICE using contract volumes traded on each day, as well as using price data from several sources, including spot, forward and derivative markets for both physical and financial products. The forward LNG netback prices the ACCC publishes for a given future month are based on the end-of-day JKM futures prices quoted by ICE in respect of the day before publication.

JKM remains the appropriate price marker for calculating historical and shorter-term forward LNG netback prices.

We also propose to publish longer-term forward LNG netback prices, extending to 5 years, based on an oil index as part of this review (chapter 5).

2.4.2. **Deducting LNG freight costs**

Asian LNG prices are typically expressed on a delivered ex-ship (DES) basis, which means that Asian LNG prices are for LNG physically delivered into Asia (for example, JKM reflects the price for LNG delivered into North Asia).

When considering whether to export LNG, an Australian LNG producer will account for shipping costs to transport LNG from Australia to the importing country.

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[17] ACCC, Gas Inquiry 2017-2020 interim report, April 2018.

[18] S&P Global Platts, *Frequently asked questions,* n.d., https://plattsmethodology.platts.com/faq, viewed 29 June 2021.

LNG freight costs represent the costs of shipping an LNG cargo (in US$/MMBtu) from the loading port to the destination port. As shown in figure 2.3, the ACCC uses a measure of LNG freight costs to determine the free on board (FOB) price at the Gladstone LNG facility.

We currently use 2 sources of data for LNG freight costs – one on historical LNG freight cost for calculating the historical LNG netback price series, and one on future LNG freight rates for calculating forward LNG netback prices.

- **Historical LNG freight costs**, provided by Platts, are daily assessments of LNG freight costs between Gladstone and Japan. These single daily values represent the implied cost of a voyage between Gladstone and Futtsu at Tokyo Bay, which Platts use as a reference delivery port for Japan/Korea. The daily freight cost estimates are based on a range of both static and variable inputs and assumptions. These inputs include:
    - Port costs – these are the costs incurred at the loading and discharge ports. Platts provides a list of assumed port costs in their specifications guide for LNG assessments and netbacks.[19]
    - Charter costs – this reflects the cost of chartering the LNG tanker for a round-trip voyage structure, and an assumed three-day loading/discharging period. A ballast rate assessment is also included to value the return leg of the voyage to account for any payment needed to position and re-position a ship.
    - Boil-off costs – this reflects the estimated value of the volume of LNG that is lost during the voyage due to boil-off.[20] Platts uses assumptions on the rates of boil-off for different legs of the voyage (such as when the tanker is in port and when it is en route) and the capacity of the LNG tanker (including its fillable volume) to estimate the quantity of LNG boil-off, which is then valued at the destination price (using the relevant JKM price assessment).
    - Fuel costs – this reflects the estimated cost of LNG tanker fuel oil costs. Platts uses assumptions on the consumption rate of fuel oil in combination with Platts's daily Singapore bunker fuel price assessment (available to subscribers) to estimate the total fuel cost for the voyage. Bunker fuel refers to fuel that is used to power ships or aircrafts.
- **Forward LNG freight costs**, provided by Argus Media under licence, are weekly assessments of LNG freight costs between Gladstone and Tokyo, for each month of a 24-month forward period. The forward freight rates comprise the same cost components incurred over a round-trip as historical freight costs, with slightly varied assumptions. These include:
    - A standard-sized dual-fuel diesel electric (DFDE) vessel for the voyage
    - Boil-off is burnt on the outward leg to power the vessel, while the return leg is powered using bunker fuel
    - The bunker fuel cost is based on the Argus assessment of Singapore high-sulphur fuel oil swaps
    - The charter cost is based on Argus's daily assessment of charter rates east of Suez, as well as its 24-month global forward curve informed by market participant indications and global LNG arbitrages.

[19] S&P Global Platts, *Specifications guide, Liquefied natural gas assessments and netbacks*, April 2020, p. 19, https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/lngmethodology.pdf, viewed 29 June 2021.

[20] Heat can cause LNG being transported to evaporate and produce boil-off gas. Boil-off gas is unavoidable and has to be removed from the tanks in order to maintain the cargo tank pressure.

The ACCC deducts historical LNG freight estimates from historical JKM assessments to derive historical LNG FOB prices at Gladstone, and deducts Argus's forward LNG freight cost estimates from JKM futures quoted by ICE, for a given future month, to calculate forward-looking FOB prices at Gladstone.

Our draft decision is that our current approach to sourcing historical and forward LNG freight costs out to 2 years remains appropriate.

However, an alternative source of LNG freight cost estimates is needed to publish longer-term forward LNG netback prices. While there are several possible alternatives, our draft decision is to source estimates of longer-term LNG freight costs from a consultant no less frequently than on an annual basis.

2.4.3. **Deducting LNG plant and pipeline costs**

The next step to calculate LNG netback prices is to deduct LNG liquefaction costs to get an indicative price at the LNG plant inlet.

The ACCC currently uses an estimate of the short-run marginal costs to produce LNG – that is, the costs an LNG producer incurs to convert uncontracted gas to LNG. These are the costs that would be incurred by the LNG producer if it exported uncontracted gas rather than supply it to the domestic market (figures 2.2 and 2.3 provide a high-level overview of these costs).

Liquefaction costs includes the value of the gas that is consumed as fuel during the liquefaction process, as well as any LNG plant operating expenditure incurred to liquefy uncontracted gas.

The ACCC does not currently account for any sunk costs incurred to produce LNG to meet the LNG producer's long-term contracts, because these costs would be incurred whether LNG producers export LNG or supply gas to the domestic market. Because these costs do not affect the relative value of the options available to LNG producers for their excess gas, exporting as LNG or supplying to the domestic market, LNG producers would not take these into account when deciding whether to export excess gas as LNG.

As such, the ACCC currently does not deduct the sunk capital costs incurred in developing the Queensland LNG projects.

In principle, only those costs that influence the net value of the options available to LNG producers should be accounted for when calculating an LNG netback price.

To estimate liquefaction costs, we use information obtained periodically from the 3 Queensland LNG producers. We make a number of assumptions based on the information available to arrive at a measure of LNG plant fuel and operating costs for use in the historical component of the LNG netback price series, and the measures used for the forward component of the series:

- **Historical component:**
  - To estimate the short-run marginal LNG plant operating expenditure, we average the short-run marginal operating costs incurred by each LNG producer in the relevant 12-month period.
  - To estimate the value of LNG plant fuel gas, we use regression analysis to measure the marginal LNG plant efficiency for each LNG producer over a given quarter. This is calculated by considering the amount of LNG that is produced for every additional unit of gas that is fed into the LNG plant. The average of the 3 Queensland LNG producer's LNG plant efficiency is used for the quarterly figures.

- **Forward component:**
    - The same estimates of short-run marginal operating costs are used for the purpose of calculating the forward LNG netback price series, however these are adjusted for inflation. This method is based on the assumption that LNG plant operating costs do not materially change over the short term.
    - To estimate the value of LNG plant fuel gas, we take a slightly different approach and use the same regression method to determine the average of each producer's LNG plant efficiency for the most recent 12-month period for which data is available (rather than by quarter).

The next step to calculate LNG netback prices is to account for pipeline transportation costs from the wellhead (the point gas is injected into the pipeline) to the LNG plant.

The ACCC currently uses short-run marginal pipeline costs to calculate both the historical and forward LNG netback price series, using data obtained directly from the Queensland LNG producers. This reflects that the current forward LNG netback price series is published over a short forward period and that LNG producers face only marginal costs when transporting additional gas to Gladstone.

Similar to LNG plant costs, the ACCC does not deduct sunk pipeline costs to calculate LNG netback prices. In practice, the LNG producers either own these pipelines or have entered into long-term gas transportation agreements with pipeline operators, which means that they would not need to build new pipelines or pay additional tariffs to transport excess gas to Gladstone. Further, sunk pipeline costs, or tariffs that need to be paid even when additional gas is not transported to Gladstone, would not affect the relative value of the options available to LNG producers for their excess gas. LNG producers would therefore not be expected to consider these costs when deciding to supply export markets or the domestic market.

To calculate LNG netback prices, the ACCC calculates an estimate of average short-run marginal transportation costs using data obtained from LNG producers and subtracts this from the effective price at the LNG plant inlet (that is, at the point at which gas is delivered to the LNG plant) to give an LNG netback price at the wellhead.

To calculate an LNG netback price at Wallumbilla, the ACCC also needs to account for the costs of transporting gas from the wellhead to Wallumbilla. Information obtained from LNG producers indicates that these costs are negligible, and because of this, we do not account for them when calculating LNG netback prices.

The end result is an estimate of LNG netback prices at Wallumbilla.

3. Developments in international LNG markets

Global liquefaction capacity and LNG supply continues to grow in large LNG exporting countries, such as Qatar and the US. LNG trade and the approaches to pricing LNG are constantly evolving.

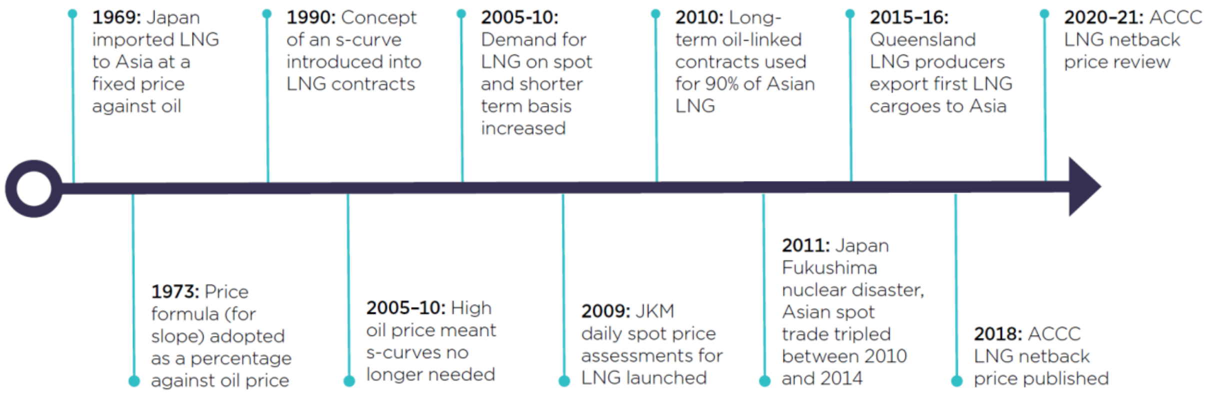
Developments in international LNG markets can have implications on Asian LNG pricing dynamics, and therefore the approach we take to calculate LNG netback prices.

3.1. Evolution of LNG pricing mechanisms

LNG contracts are typically priced against oil prices, which historically reflected that oil was an alternative fuel source for power generation.

During periods of higher and lower oil prices, pricing mechanisms in LNG contracts have changed to balance the risks faced by market participants (figure 3.1).

Figure 3.1: Changes to LNG pricing mechanisms



Around 1973, LNG contracts adopted a price formula (or slope) expressed as a percentage of the oil price. This protected sellers against oil price drops and provided buyers with security that LNG would be supplied irrespective of the oil price.

During the 1990s, the price formula adopted an ‘s-curve’, which in practice changes the slope when oil prices fall below or exceed specified levels. This primarily provided LNG buyers with safeguards against higher oil prices.

During the 2000s, higher and more volatile oil prices exceeded the upper limits of most negotiated contract price ranges, requiring parties to renegotiate the LNG contract slopes. LNG sellers no longer required the s-curves for downside price protection and in some cases, contracts reverted to a straight line slope.

Demand for spot LNG or shorter-term contracts from buyers who already had term contracts in place increased between 2005 and 2010. This coincided with India and China starting to import LNG. Spot and short-term LNG sales also started to adopt new forms of pricing referenced to prices in key gas hubs. This is because Asia did not have an established gas hub.

In 2009, Platts began publishing Japan Korea Marker (JKM) assessments of LNG spot prices (delivered into northeast Asia). JKM is increasingly becoming more accepted for spot and shorter-term LNG pricing in Asia (chapter 5).

Long-term LNG contracts linked to oil remain prevalent in the Asian LNG market (chapter 5). In 2020, oil-linked term cargoes comprised about two-thirds of supply into Asia.[21]

LNG pricing in Asia is likely to continue to evolve, especially with a range of new LNG projects from different regions set to begin supplying global LNG markets by 2024.

3.2. LNG demand is increasing rapidly

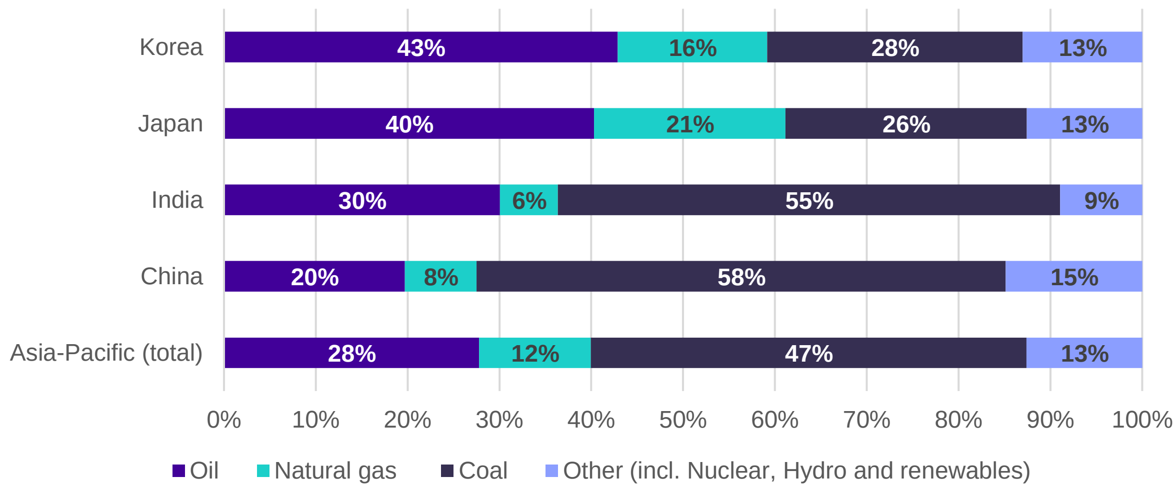
Increasing global demand for natural gas has led to substantial increases in the number of countries involved in LNG trade. By 2020, LNG was exported from 20 countries and imported into 43 countries.[22] In 2010, only 23 countries imported LNG.

3.2.1. Asia

Asia is the world's largest energy-consuming region,[23] and a number of Asian countries are transitioning from coal to natural gas (and other forms of cleaner energy) for their power generation needs.[24] Wood Mackenzie note the key drivers of the transition to natural gas are carbon reduction targets and the need for secure energy supply.[25]

In 2019, 47% of the Asia-Pacific energy needs were met by coal, while natural gas only provided 12% of the energy supply (figure 3.2). China (58%) and India (55%) are the main drivers of coal usage in the Asia-Pacific region, while natural gas usage accounted for 8% and 6% of their energy fuel sources, respectively.

Figure 3.2: Selected Asian countries, primary energy source by fuel, percentage of total in 2019



Source: ACCC analysis of BP Statistical Review of World Energy 2020.

In 2020, most Asian countries adopted new energy policies to reduce emissions.

21 Reuters, *RPT-Oil-Linked LNG may be here to stay after spot market skyrockets*, January 2021, https://www.reuters.com/article/lng-contracts-pricing-idUSL1N2JQ02W, viewed 1 June 2021.

22 GIIGNL, *LNG markets and trade*, n.d., https://giignl.org/lng-markets-trade-0, viewed 1 June 2021.

23 BP, Statistical Review of World Energy 2020, June 2020, https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2020-full-report.pdf, viewed 29 June 2021.

24 White & Case, *Environmental concerns spur Asia to reduce reliance on coal*, 5 February 2021, https://www.whitecase.com/publications/alert/environmental-concerns-spur-asia-reduce-reliance-coal, viewed 1 June 2021.

25 Wood Mackenzie, preliminary report, June 2021, p. 8.

- China announced that its 2060 goal of net-zero carbon emissions would be achieved by replacing coal with natural gas, and in doing so, reduce its CO_2 emissions peak before 2030.[26]
- Japan announced that by 2050 its goal is to achieve net-zero greenhouse gas emissions.[27] To achieve this target, Japan will invest in renewables and change its longstanding policy on coal power generation.[28]
- Korea stated that by 2050 it would reduce greenhouse gases to zero and phase out all coal power plants or convert them to run on cleaner-burning LNG by 2030.[29]
- India did not commit to a net-zero emissions goal by 2050, however it announced that it would increase natural gas usage from 6% to 15% by 2030.[30]

Asian LNG demand is expected to remain strong in the near-term as countries decarbonise their energy mixes. Shell's LNG Outlook 2021 suggests that Asia is expected to account for 75% of total global LNG demand growth, estimated to reach 700 million tonnes per annum (mtpa) by 2040.[31]

According to McKinsey, increasing the Asia-Pacific's share of natural gas consumption from 12% to 20% is estimated to add the equivalent of more than 400 mtpa to LNG demand, doubling the size of the current global LNG market.[32]

LNG imports in China and in emerging Asia (which includes India) are expected to be the key drivers of LNG demand growth by 2026 (figure 3.3). Demand for LNG is also expected to gradually decline in more mature LNG markets, particularly as countries such as Japan focus on renewables over the medium to longer term.

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26 Energy Quest, *North Asian LNG imports rose through 2020,* 19 March 2021, https://www.energyquest.com.au/north-asian-lng-imports-rose-through-2020/, viewed 1 June 2021.

27 IEA, *Japan 2021 Energy Policy Review*, March 2021, https://www.iea.org/reports/japan-2021, viewed 1 June 2021.

28 Prime Minister of Japan and his Cabinet, *Policy Speech by the Prime Minister to the 203rd Session of the Diet*, 28 October 2020, https://japan.kantei.go.jp/99_suga/statement/202010/_00006.html, viewed 1 June 2021.

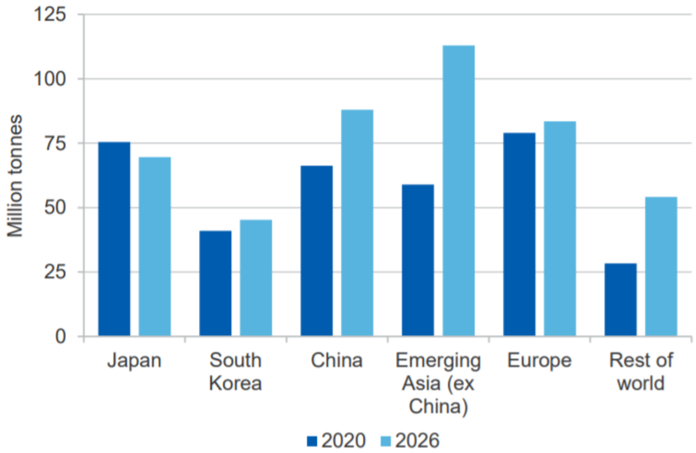
29 The Government of the Republic of Korea, *2050 Carbon Neutral Strategy of the Republic of Korea*, December 2020, https://unfccc.int/sites/default/files/resource/LTS1_RKorea.pdf, viewed 1 June 2021.

30 IEA, *India 2020 – Energy Policy Review*, https://niti.gov.in/sites/default/files/2020-01/IEA-India%202020-In-depth-EnergyPolicy_0.pdf, viewed 1 June 2021.

31 Shell, *LNG Outlook 2020*, https://www.shell.com/energy-and-innovation/natural-gas/liquefied-natural-gas-lng/lng-outlook-2020, viewed 1 June 2021.

32 McKinsey & Company, *The future of liquefied natural gas: Opportunities for growth, 21 September 2020*, https://www.mckinsey.com/industries/oil-and-gas/our-insights/the-future-of-liquefied-natural-gas-opportunities-for-growth, viewed 1 June 2021.

Figure 3.3: Current and expected LNG imports in selected regions in 2020 and 2026



Source: Office of the Chief Economist, Resources and Energy Quarterly, March 2021

LNG is expected to play a key role in the Asian region as countries adapt their energy demand mixes to meet future emissions targets. Australia will remain an important source of LNG supply to Asia given its proximity.

3.2.2. **Europe**

Natural gas is an important part of Europe's energy supply mix, accounting for 23% of its power generation, heating and industrial process needs.

Between 2021 and 2025, to sustain Europe's current energy needs, natural gas imports are expected to increase by 10%, or by 45 billion cubic metres (BCM) per annum.[33] This is because domestic gas production in Europe (excluding Norway) is expected to decrease by around 40% by 2025.[34]

The Netherlands, where the Title Transfer Facility (TTF) is located, is one example of lower gas production impacting future supply. By mid-2022, gas production is expected to cease due to production causing seismic activity. In 2019-20, production capacity was limited to 11.8 BCM, in comparison to 53 BCM in 2013.[35]

Norwegian pipeline gas supplies are expected to remain constant and provide flexible gas to the European market. Recently, Norway reported fewer offshore discoveries which is expected to impact supply from 2030.[36] Norway committed to a target of at least 40% reduction of greenhouse gas emissions by 2030 compared to 1990 levels, which may further influence its decisions around gas production potentially impacting supply.

Europe is in the process of diversifying its natural gas supply sources to ensure its energy security. LNG is a diversified source of gas that can provide stability, particularly in the

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33 IEA, *Gas 2020: 2021-2025: Rebound and beyond*, June 2020, https://www.iea.org/reports/gas-2020/2021-2025-rebound-and-beyond, viewed 1 June 2021.

34 ibid.

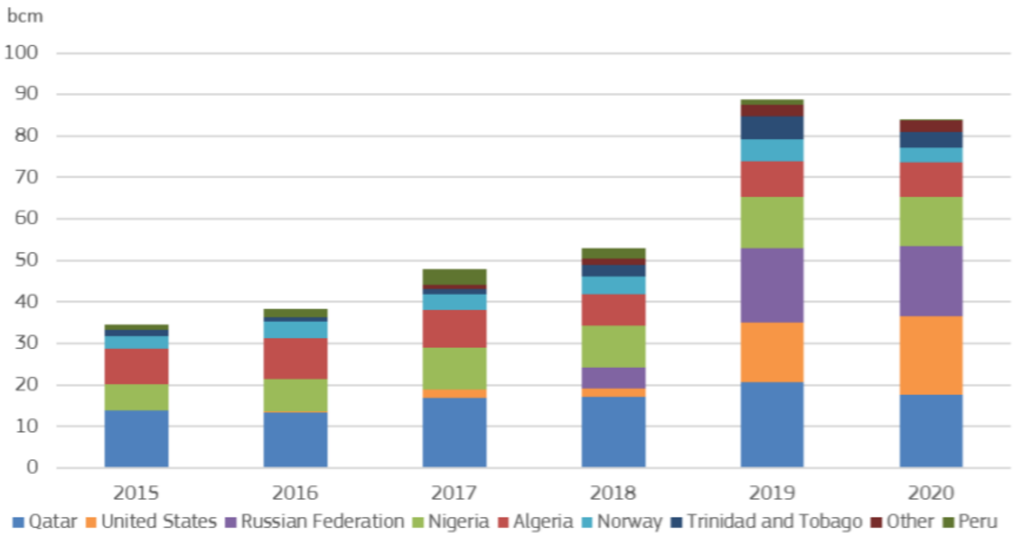
35 OECD & IEA, *The Netherlands's Effort to Phase Out and Rationalise its Fossil-Fuel Subsidies*, 2020, https://www.oecd.org/fossil-fuels/publication/2020-OECD-IEA-review-of-fossil-fuel-subsidies-in-the-Netherlands.pdf, viewed 1 June 2021.

36 Argus Media, *Norway's oil, gas exploration falls in 2020: NPD*, 27 October 2020, https://www.argusmedia.com/en/news/2153882-norways-oil-gas-exploration-falls-in-2020-npd, viewed 1 June 2021.

context of declining domestic production and as long-term pipeline supply contracts progressively expire.[37]

Europe is the second largest importer of natural gas and LNG after Asia. Importantly, Qatar, the United States and Russia are the 3 main suppliers of LNG into the European Union, particularly since 2019 (figure 3.4). Russia is also the only pipeline supplier able to provide Europe the increased gas volumes needed to meet peak demand. In 2020, Russia accounted for 43% of the pipeline gas supply into the EU, and around 20% of total LNG imports.[38]

Figure 3.4: Annual LNG import from the main suppliers to the EU



Source: European Commission data

Europe plays an important role in balancing the global LNG market, by absorbing and storing large volumes of LNG. Europe received fewer LNG cargoes than usual in late 2020 due to stronger demand in Asia, drawing on gas storage instead.[39] European storage levels were around 37% in March 2021 compared to 60% in March 2020.[40] European gas storage is used as a buffer and demand for LNG is expected to increase to replenish storage levels. Ultimately, the amount of LNG supplied into Europe will depend on supply and the demand pull from Asia.

3.3. Flexible LNG supply continues to come online

Recent growth and expected LNG supply capacity in Qatar and the US is likely to have short and long-term implications on global LNG trade. Qatar operates at the lower end of the global LNG cost curves, and both have the flexibility to arbitrage cargoes between Europe and Asia.

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37 IEA, *Gas 2020: 2021-2025: Rebound and beyond*, June 2020, https://www.iea.org/reports/gas-2020/2021-2025-rebound-and-beyond, viewed 1 June 2021.

38 European Union, *Quarterly report on European gas markets*, vol. 13, no. 4, Q4 2020, https://ec.europa.eu/energy/sites/default/files/quarterly_report_on_european_gas_markets_q4_2020_final.pdf, viewed 1 June 2021.

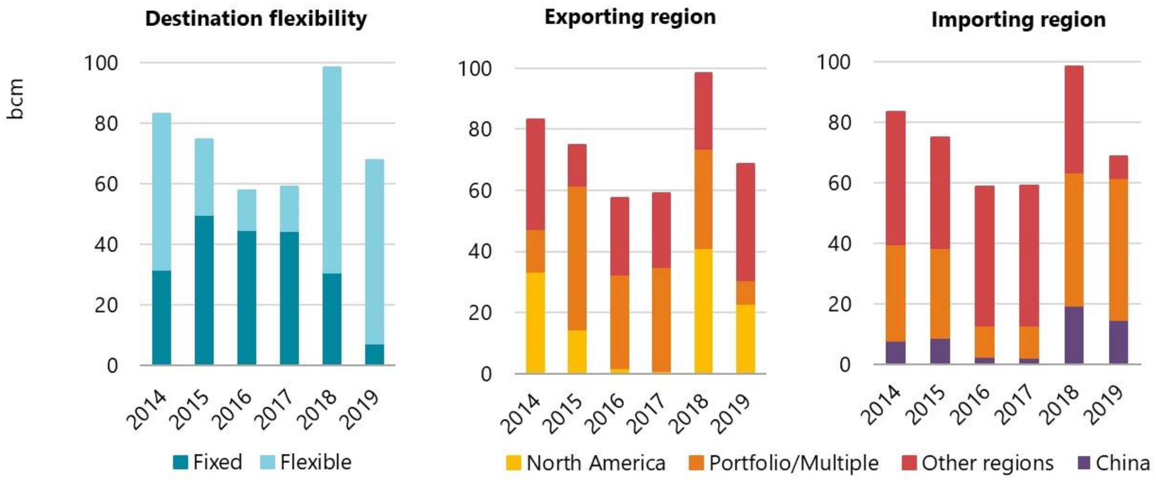
39 ibid., p. 4.

40 Reuters, *Europe's unusually low gas stocks set to underpin prices*, 2 March 2021, https://www.reuters.com/article/us-europe-gas-graphic-idUSKBN2AT2SU, viewed 1 June 2021.

LNG buyers in mature and emerging markets are becoming less interested in long-term contracts with inflexible terms. Shorter-term contract arrangements are increasingly being favoured as new LNG supply becomes available.

IEA data suggests that newly executed LNG contracts in the period from 2014 to 2019 had higher levels of destination flexibility (figure 3.5).[41] This trend towards greater destination flexibility in LNG contracts was primarily driven by new LNG contracts with US LNG projects.[42]

Figure 3.5: Newly executed LNG contracts by destination flexibility, exporting region and importing region, 2014 to 2019



Source: IEA

LNG portfolio players are influencing global LNG trade by further driving greater flexibility in LNG contracts (figure 3.5). These parties hold portfolios of LNG supply from different regions as well as various shipping, storage and regasification assets. By optimising supply and infrastructure, portfolio players can provide LNG to end users as well as to participants in short- and medium term markets more efficiently than the traditional point-to-point arrangements. For example: traditional point-to-point arrangements. For example:

- Royal Dutch Shell, holder of the world's biggest LNG supply portfolio, entered agreements to supply several Asian buyers with LNG from any of its global projects.[43]
- France's Total, with the second-largest LNG portfolio, doubled its overall supply to around 40 mtpa, of which around 65% has flexible destination clauses.

In recent years, the extent of spot and short-term contracts as a share of total global LNG trade volume has increased substantially (figure 3.6). In 2020, LNG volumes traded on a spot and short-term basis accounted for 37% of global LNG trade.[44] Short-term volumes were driven by portfolio players and increased amounts of uncontracted LNG cargoes. In contrast, the share of volumes traded under long-term contracts declined and cargo cancellations in 2020 further contributed to this decline.

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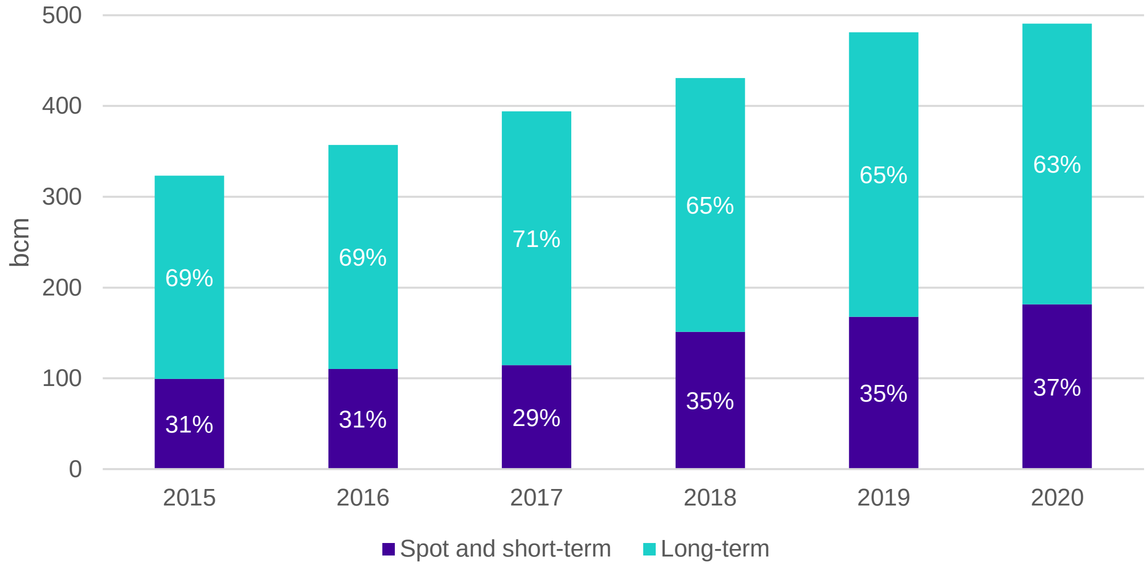
41 IEA, *Global Gas Security Review 2019*, September 2019, https://www.iea.org/reports/global-gas-security-review-2019, viewed 1 June 2021.

42 GIIGNL, Annual Report 2014, 2018 and 2019, https://giignl.org/publications, viewed 30 June 2021.

43 Reuters, *Glut forces LNG producers to offer flexible deals from global portfolios,* 24 April 2019, https://www.reuters.com/article/uk-lng-portfolio-sales-idUKKCN1RZ2KV, viewed 1 June 2021.

44 IEA, *Gas Market Report, Q1-2021*, January 2021, https://www.iea.org/reports/gas-market-report-q1-2021/2020-highlights#abstract, viewed 1 June 2021.

Figure 3.6: Spot and short-term LNG contracts as a share of total trade, 2015–2020



Source: IEA Gas Market Report, Q1-2021.

Platts suggested in 2020 that around one-third of active LNG contracts are due to expire between 2020 and 2025. During the same period, liquefaction capacity is also expected to grow by 20%, quadrupling the amount of currently uncontracted LNG.[45] Given current trends, this has the potential for LNG traded under spot and shorter-term contracts to further increase as flexible LNG supply comes online.

Global markets have become increasingly linked and gas prices in a given market can be responsive to the supply and demand fundamentals in regions outside of their immediate proximity.

The continued evolution of LNG market has the potential to increase the relative influence of different prices markers, particularly as LNG markets become more flexible and as short-term trade grows. This might mean that different price markers converge over time, and to the extent that this occurs, use of one price marker will necessarily reflect other markers and their market dynamics.

[45] S&P Global Platts, *Analysis: Lower-for-longer LNG prices to put buyers in the sweet spot for years*, 28 October 2020, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/102820-analysis-lower-for-longer-lng-prices-to-put-buyers-in-the-sweet-spot-for-years, viewed 1 June 2021.

4. The length of the forward LNG netback price series

The ACCC began publishing the LNG netback price series in 2018 to increase transparency in the east coast gas market (chapter 2), and is undertaking this review to ensure that the ACCC's approach remains appropriate.

ACCC's draft decision

Our draft decision is to:

- continue to publish historical and short-term forward LNG netback prices extending to 2 years, based on JKM spot prices
- publish longer-term forward LNG netback prices extending to 5 years, based on an oil-linked index.[46]

The ACCC currently publishes forward LNG netback prices extending to 2 years, which reflects:

- relatively low liquidity in the Japan Korea Marker (JKM) futures market beyond a period of 2 years[47]
- limited available data on forward LNG freight rates from Gladstone to the key export markets in northeast Asia beyond a period of 2 years.[48] LNG freight costs, which are deducted in calculating LNG netback prices, can be material and have a significant impact on calculated LNG netback prices.
- that when we developed the existing LNG netback price series, we considered that the primary alternative for suppliers, other than domestic gas supply, was to export LNG into the Asian LNG spot markets over the short term.

In the issues paper, we requested stakeholder views on a range of issues, including what reference price should be used to calculate LNG netback prices and whether the ACCC should publish forward LNG netback prices over a longer forward period.

Based on our assessment of information provided by stakeholders and expert advice provided by Wood Mackenzie, JKM continues to reflect the opportunity cost to LNG producers of supplying the domestic market. However, the ACCC's current JKM-based LNG netback price series has limitations, particularly in terms of the forward length of the series.

Publishing longer-term forward LNG netback prices would help C&I users negotiate longer-term domestic gas supply agreements (GSAs) of longer than 2 years.

4.1. The relevant supply periods for LNG netback prices to reflect domestic east coast market dynamics

There are 2 factors that suggest that longer-term LNG netback prices, based on oil indexes, are relevant to the domestic market.

First, a significant portion of domestic offers are for supply terms of longer than 2 years. The current LNG netback price series provides limited information to C&I users who are negotiating GSAs with terms longer than 2 years.

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46 LNG strips are multi-cargo contracts for supply over a short to medium-term.

47 Market participants are not likely to view JKM as a reliable indicator of future Asian LNG spot prices beyond this period. For example, on 14 June 2021, open interest in JKM futures listed on the Intercontinental Exchange fell to the equivalent of about 15 PJ in July 2023 compared to 105 PJ in August 2021.

48 LNG freight costs, which are deducted in calculating LNG netback prices, can be material and have a significant impact on calculated LNG netback prices.

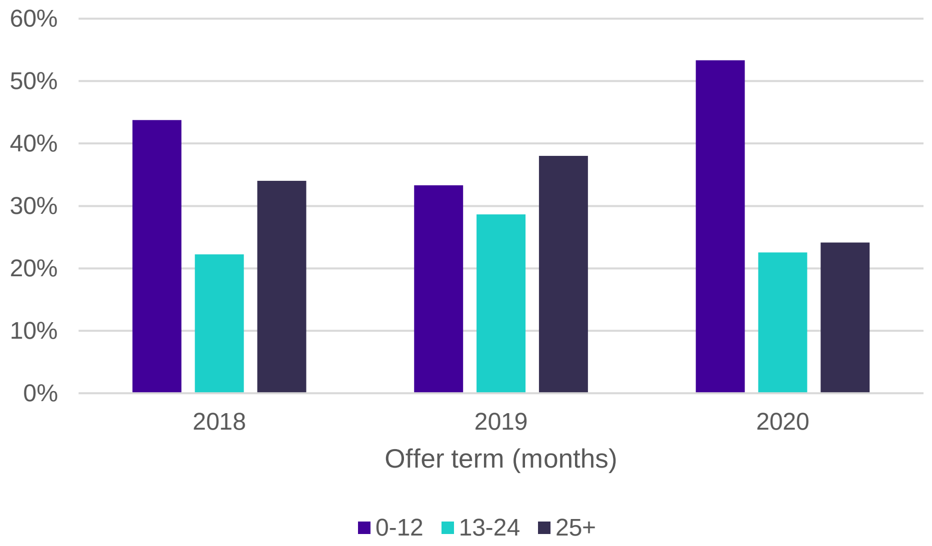
Second, some domestic suppliers, including LNG producers, already consider medium-term LNG contracts prices, which are typically calculated with reference to oil indexes, as a benchmark for domestic prices.

4.1.1. A significant number of domestic offers are for terms longer than 2 years

The ACCC periodically collects data on offers made by suppliers in the east coast gas market.

This data shows that many offers made by suppliers are for terms longer than 2 years (figure 4.1).

Figure 4.1 ACCC analysis of the term of offers in the east coast gas market



Source: ACCC analysis of data supplied by gas producers

While the majority of offers made in the east coast are for 2 years or less, there are typically a significant number of offers for supply terms longer than 2 years. About 25% of gas offers in 2020 were for supply over terms longer than 2 years, with this proportion even higher in 2018 and 2019 (in which almost 40% of offers longer than 2 years).[49]

The ACCC has previously noted the general trend in the east coast gas market towards shorter-term GSAs. This trend may continue, but it is not yet clear whether the east coast gas market will shift entirely to shorter-term GSAs. In our view, gas producers and C&I users are likely to continue to seek longer-term GSAs, in part to underpin investments to develop new gas supply.

Negotiations for gas supply can also occur well in advance of the start date of the gas supply agreement.

The short length of the ACCC's current LNG netback price series limits how useful it is to C&I users seeking longer-term domestic GSAs. That said, the majority of offers made are for terms of 2 years or less. The current LNG netback price series remains highly relevant for C&I users seeking offers for GSAs with terms of 2 years or less.

[49] The number of offers for a term of one year increased substantially in 2020, which may reflect increased supply from LNG producers (as the ACCC noted in our Gas Inquiry 2017–2025 January 2021 interim report).

4.1.2. **Some LNG producers already consider medium-term LNG prices**

In 2020, the ACCC undertook a deep dive examination of the pricing strategies of key gas suppliers in the east coast market, including the Queensland LNG producers. The examination was motivated by concerns about the disparity between domestic price offers and LNG netback prices.

The ACCC's preliminary findings, published in January 2021, have implications for this review.

The development of the Queensland LNG projects connected the east coast gas market to global LNG markets. In practice, gas suppliers are able to export LNG:

- under long-term LNG Sale and Purchase Agreements (SPAs), such as those entered into between LNG producers and their foundation offtake LNG buyers
- in short to medium-term multi-cargo LNG contracts (commonly referred to as LNG 'strips') – prices in LNG strips are often directly linked to oil prices
- as one-off single cargo sales into LNG spot markets.

While the majority of LNG exported from the east coast gas market is sold under long-term oil-linked LNG SPAs, uncontracted gas produced by or available to the LNG producers, beyond that required to fulfil their long-term SPAs, can be exported through LNG strips or as LNG spot sales.

The prices that LNG producers expect to receive for exporting gas as LNG represent an opportunity cost for east coast suppliers in supplying the domestic market (chapter 2).

The ACCC's work on pricing strategies found that while domestic suppliers continue to view JKM as a relevant benchmark over the short term, some also consider that prices in medium-term LNG strips, which are calculated using oil indexes, are also relevant to the domestic market.

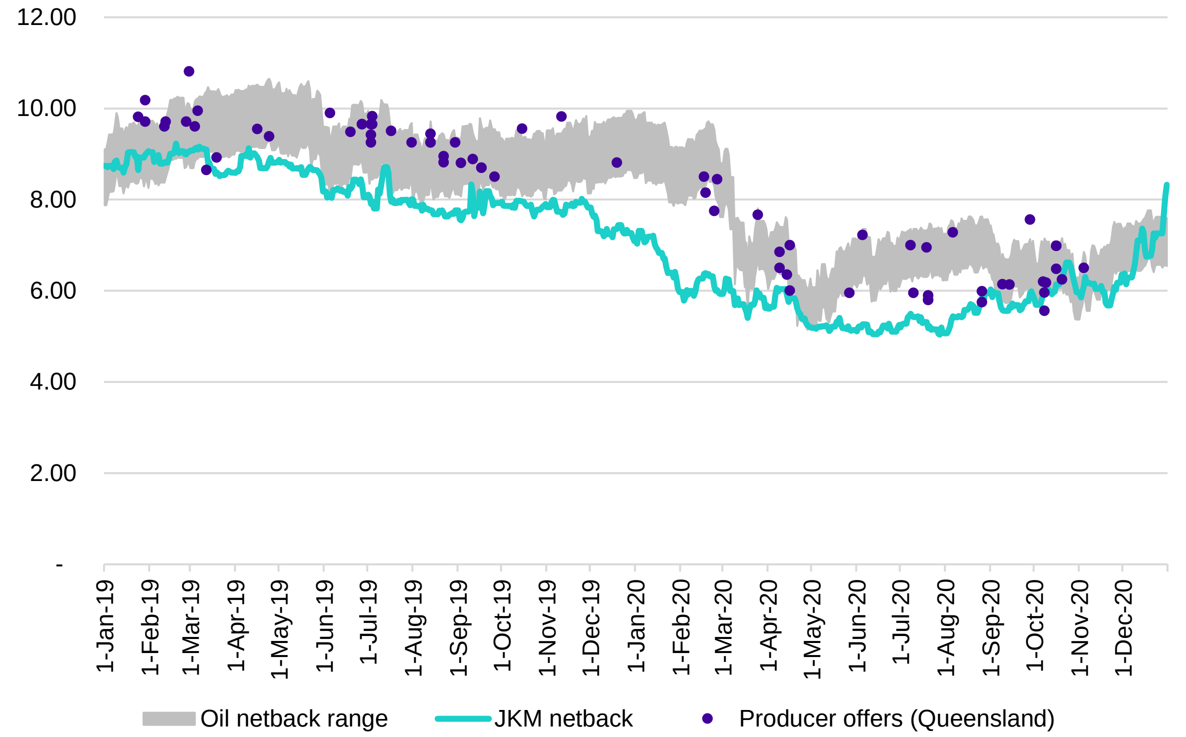
The ACCC's review of documents provided by the LNG producers indicate that some LNG producers have actively considered entering into LNG strips and that their domestic pricing strategies appear to have been influenced by the prices in such LNG contracts (with these prices acting as a reference for the domestic market).

Some non-LNG producers also appear to have been influenced by prices in LNG strip contracts. For example, one domestic gas producer appears to have routinely based its pricing assumptions for uncontracted gas supply on oil-linked prices for LNG strips. Another said that while JKM netback was more relevant for domestic spot prices and 1–2 year GSAs, longer-term LNG contract prices (beyond 2 years) were more relevant for multi-year domestic GSAs.

Given that LNG strip prices have historically been higher and more stable than Asian LNG spot prices, this use of LNG strip prices as a benchmark may be part of the reason we have seen a disparity emerge between LNG netback prices (based on Asian spot prices) and domestic prices.

Since early 2019, producer offers in Queensland and the southern states have mostly been above JKM netback, and generally consistent with the range of oil-based LNG netback prices (figures 4.2 and 4.3). Around two-thirds of these offers were part of supply negotiations for periods longer than two years — however, the duration of offers does not appear to have had a significant influence on price.

Figure 4.2: Producer offers for 2021 supply in Queensland against LNG netback prices based on expected JKM and oil prices

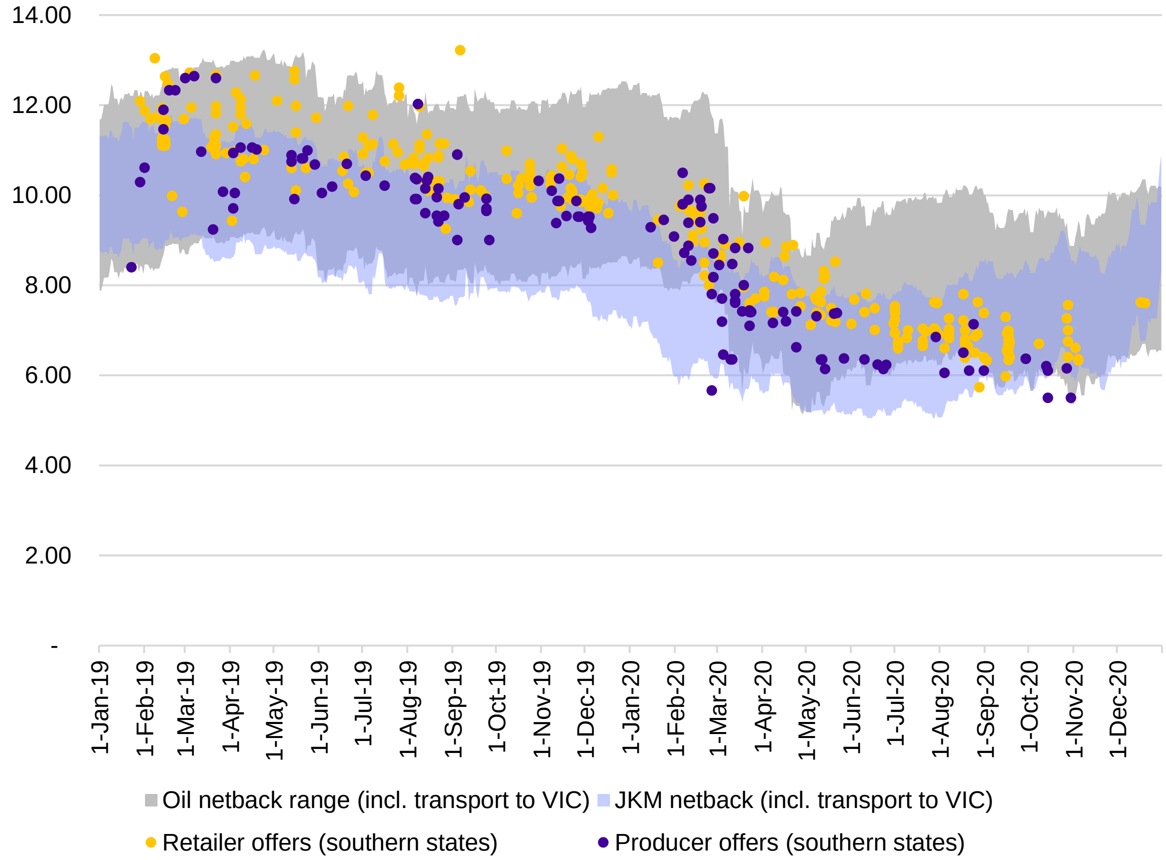


Source: Bloomberg, ICE, RBA, ACCC analysis of information provided by suppliers.

Note: The range of oil-based netback prices shown in the chart is based on some of the most common methodologies and inputs we have observed suppliers using in internal documents and pricing models. This includes different assumptions relating to LNG contract slope, liquefaction losses and pipeline costs.[50]

[50] ACCC, Gas Inquiry 2017-2025 interim report, January 2021, p. 109.

Figure 4.3: Producer and retailer offers for 2021 supply in southern states against LNG netback prices based on expected JKM and oil prices (plus transportation costs)



Source: Bloomberg, ICE, RBA, ACCC analysis of information provided by suppliers.

Note: The range of oil-based netback prices shown in the chart is based on some of the most common methodologies and inputs we have observed suppliers using in internal documents and pricing models. This includes different assumptions relating to LNG contract slope, liquefaction losses and pipeline costs.[51]

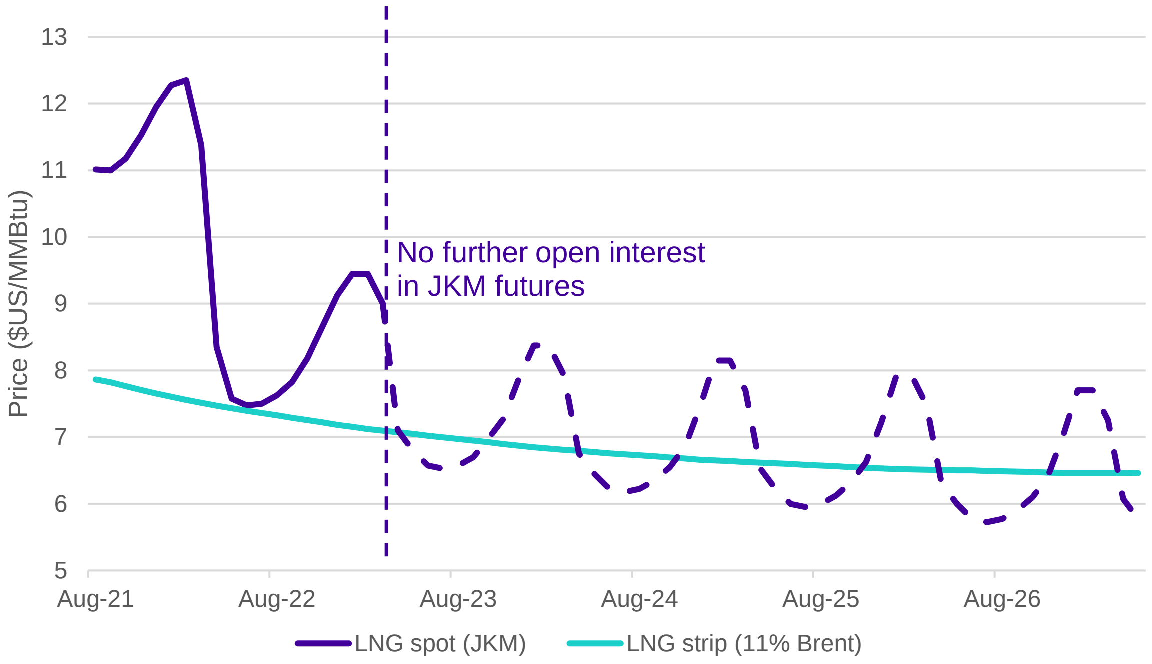
While offers over period shown in figure 4.2 appear to have a closer relationship with oil-based netback prices than JKM netback prices, JKM prices and LNG strip prices based on oil indexes are both have had some influence and are relevant for domestic pricing, with the latter suitable as a reference for extended forward LNG netback prices (chapter 4).

JKM prices and LNG strip prices based on oil indexes are both relevant for domestic pricing, with the latter suitable as a reference for extended forward LNG netback prices (chapter 4).

Current futures prices for JKM and oil (using Brent) suggest that LNG spot prices and LNG strip prices will be broadly similar over the next 5 years (noting significant uncertainty due to limited liquidity in JKM beyond 2 years) (figure 4.4).

[51] ACCC, Gas Inquiry 2017-2025 interim report, January 2021, p. 109.

Figure 4.4: LNG futures based on JKM and oil indexes



Source: ACCC analysis of ICE JKM futures, Bloomberg Brent Futures.

Note: LNG strips prices have been calculated at 11% of Brent futures. The dashed line indicates JKM futures beyond a period of 2 years.

4.2. Stakeholder views on extending the price series beyond 2 years

In submissions, stakeholders expressed a range of views on the merits of extending the forward netback price curve.

4.2.1. Most C&I users want a longer-term forward LNG netback price

C&I users strongly support the ACCC extending the netback price series forward curve, with all but one C&I user supportive of the LNG netback price series including longer-term forward LNG netback prices.

Chemistry Australia, Qenos and Incitec Pivot Limited suggest the ACCC should publish 3, 4, 5 and 10 year forward curves, aligned to the US Henry Hub gas marker due to its depth and liquidity.[52] The Energy Users Association of Australia and Manufacturing Australia also consider the forward netback series should be extended out to 10 years using a sufficiently liquid benchmark.[53]

Qenos notes there is limited value in monthly data beyond a 2 year forward period and suggest that longer-term netback prices could be published as a single annual netback price.[54] Qenos also notes that the ACCC would need to consider sources of data on future LNG freight rates to calculate longer-term netback price series (we discuss estimating forward LNG freight rates in chapter 5).

52 Chemistry Australia, Submission to the issues paper, April 2021; Qenos, Submission to the issues paper, April 2021; Incitec Pivot, Submission to the issues paper, April 2021.

53 EUAA, Submission to the issues paper, April 2021; Manufacturing Australia, Submission to the issues paper, April 2021.

54 Qenos, Submission to the issues paper, April 2021.

C&I users suggest that extending forward LNG netback prices would assist them in their negotiations with gas suppliers, noting that C&I users in the domestic market routinely consider and enter into GSAs with terms longer than 2 years. The Major Energy Users (MEU) notes in their submission that contract terms available for domestic C&I users have traditionally been for terms of 3 to 5 years, with some contracts being for more than 5 years.[55]

The MEU also notes that longer-term contracts are often preferred by C&I users as longer-term contracts provide greater certainty around recovery of investments made by manufacturers. Chemistry Australia also stated that it is important that the length of the forward netback curve is consistent with the duration of different domestic GSAs.[56]

The Chicago Mercantile Exchange (CME) also supports the views put forward by C&I users, noting that negotiations for domestic GSAs might require a longer-term LNG netback as these GSAs can exceed 2 years in duration.[57]

4.2.2. Gas suppliers generally do not support the ACCC extending the LNG netback price series

ConocoPhillips Australia and Origin (who are JV partners in the APLNG export project) do not support extending the current LNG forward netback price series due to limited liquidity in the JKM futures market beyond 2 years.[58]

ConocoPhillips Australia, however, recommends the ACCC extend forward curve as JKM liquidity continues to grow in the future, noting the growth in LNG spot trade, the importance of JKM as an indicator of Asian LNG prices and growing JKM liquidity.

Origin suggests that there are no appropriate methods that could be used to accurately calculate longer-term LNG netback prices.

GLNG suggests that the current forward JKM-based netback is most appropriate as a short-term price guide for domestic offers and GSAs with supply terms up to 2 years, and that is has limited relevance for longer-term domestic GSAs.

GLNG notes that the calculation of longer-term netback prices, if possible, should be based on as many long-term LNG contracts as possible, and be limited to contracts for supply into the Asian LNG market (being the relevant market for Australian LNG producers). GLNG also stated that a long-term netback should also reflect the LNG producers' opportunity costs and thus deduct only the variable costs faced by the LNG producers.[59]

While GLNG suggests that longer-term LNG netback prices could be helpful, they note that it would be difficult to develop.[60] This reflects availability of LNG price data, and the potential need for normalisation of LNG contract prices that reflect bespoke contract terms and conditions.[61] For this reason, GLNG does not support the ACCC publishing longer-term forward LNG netback prices.

Shell (a JV participant in the QCLNG project) also does not support the ACCC extending the forward LNG netback price series. Shell considers that a longer-term netback (beyond 2

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55 MEU, Submission to the issues paper, April 2021.

56 Chemistry Australia, Submission to the issues paper, April 2021.

57 CME, Submission to the review issues paper, April 2021.

58 ConocoPhillips Australia, Submission to the issues paper, April 2021; Origin, Submission to the issues paper; GLNG, Submission to the issues paper, April 2021.

59 GLNG, Submission to the issues paper, April 2021, pp. 7–8.

60 GLNG, Submission to the issues paper, April 2021, p. 4.

61 These terms and conditions include: commencement date and term of supply, volume, risk allocation (delivery point, shortfall risk, permitted interruptions and force majeure provisions) and offtake flexibility.

years) would have decreasing and limited benefit for price transparency in the east coast gas market.[62] Shell considers other domestic market factors, including production costs, pipeline constraints and the development of an import terminal, become more relevant the further the forward period extends. Shell also notes that there is less certainty in the parameters used to calculate LNG netback prices over the longer term (such as JKM).

Finally, Santos suggests that forward LNG term prices are not relevant at all to long-term domestic offers, which are predominately influenced by production costs and associated risks.[63] Santos further notes that only one or two of the Queensland LNG projects have sufficiently large uncontracted reserves for which they would need to consider forward LNG contract prices relative to domestic GSA pricing.

4.3. Short-term LNG netback prices remain relevant

Our draft decision is to continue publishing historical and short-term 2-year forward LNG netback prices using JKM.

When we developed the LNG netback price series in 2018, the LNG producers were likely to be the marginal suppliers into the east coast gas market and their key alternative to supplying uncontracted gas into the domestic market was to sell into Asian LNG spot markets.

This continues to be the case. The ACCC’s examination of the pricing strategies of east coast gas suppliers confirms that many continue to view JKM as a relevant benchmark for the east coast gas market over the short term. For example, one LNG producer noted in 2019 that they considered JKM-based LNG netback prices as a benchmark for a range of domestic transactions (which had terms of up to 2 years). Further, some suppliers in the southern states viewed LNG netback prices, based on JKM, as a key input into understanding pricing dynamics in the southern states.

Many stakeholder submissions also note that JKM remains a key benchmark for the domestic market and that the ACCC should continue to publish LNG netback prices using JKM.

Wood Mackenzie’s expert advice is that short-run LNG netback prices, based on JKM, are a relevant reference for gas prices in the east coast gas market.[64] To the extent that other price markers, such as Henry Hub, influence Asian prices, this influence would already be reflected in JKM (and therefore in our existing forward LNG netback prices).

4.4. Longer-term forward LNG netback prices would improve market transparency

The ACCC’s draft decision is to publish additional longer-term forward LNG netback prices, alongside JKM-based forward LNG netback prices, as part of the LNG netback price series.

An extended LNG netback price series would help inform negotiations between suppliers and C&I users for longer-term domestic GSAs. This would also benefit a significant number of negotiations.

It would also make available to C&I users information that some domestic gas producers already have access to. By publishing longer-term forward LNG netback prices, the ACCC will address an existing information asymmetry.

62 Shell, Submission to the issues paper, April 2021.

63 Santos, Submission to the issues paper, April 2021.

64 Wood Mackenzie, preliminary report, June 2021, p. 37.

However, we also recognise the substantial challenges in developing longer-term LNG netback prices, including data availability, quality and reliability. This includes availability of reliable data on which percentage, or slope, to apply to oil indexes to derive an estimate of medium-term LNG prices. We also recognise that there are potentially risks associated with publishing longer-term forward LNG netback prices (chapter 5).

On balance, our preliminary view is the benefits of publishing longer-term forward LNG netback prices will outweigh the associated risks. We seek stakeholder feedback on the ACCC's draft decision.

Wood Mackenzie's expert advice is that longer-term LNG netback prices, calculated using oil indexes, will provide east coast gas market participants a more relevant reference for their longer-term domestic GSAs.[65]

Extending the length of the forward LNG netback price series raises questions around the ACCC's choice of LNG reference price (chapter 5) and sources of LNG freight data (chapter 6).

The ACCC seeks feedback on any of the following issues. Where possible, please include supporting information, data and specific examples in your responses.

1. Is the ACCC's draft decision to continue publishing a 2-year forward LNG netback price series appropriate? Should the ACCC continue to publish a 2-year forward LNG netback price series?
2. Is the ACCC's draft decision to publish additional longer-term forward LNG netback prices appropriate? Should the ACCC publish additional longer-term forward LNG netback prices?
3. Over what length of time should the ACCC publish additional longer-term forward LNG netback prices (such as 3 or 5 years)?
4. What other issues should be considered when publishing longer-term forward LNG netback prices.

65 Wood Mackenzie, preliminary report, June 2021, p. 37.

5. LNG price markers to calculate the LNG netback price series

The Australian Government requested that the ACCC review the LNG netback price series to ensure that it remains fit for purpose given significant changes in global LNG and gas markets in recent years. In doing so, the government specifically requested that the ACCC consider the impact of international markets on domestic gas pricing.

The issues paper sought feedback from stakeholders on all issues relevant to the LNG netback price series, including which LNG or gas reference price the ACCC should use to calculate LNG netback prices.

The ACCC currently uses the Japan Korea Marker (JKM) to estimate LNG netback prices. As noted by stakeholders, however, there are other price markers that could potentially be used to calculate LNG netback prices on the east coast.

ACCC's draft decision

Our draft decision is to:

- continue to publish historical and short-term forward LNG netback prices extending to 2 years using JKM spot prices (consistent with our current approach)
- publish longer-term forward LNG netback prices extending to 5 years using oil indexes.

The ACCC will source an estimate of the appropriate percentage, or slope, to apply to oil indexes to calculate LNG prices from a consultant no less frequently than on an annual basis.

Asia is, and is likely to remain, the key export market for Queensland LNG. Asian LNG prices are expected to therefore represent the opportunity costs to LNG producers of supplying uncontracted gas to the domestic market.

JKM is increasingly accepted by LNG market participants as the established benchmark for Asian LNG spot prices over a forward period of up to 24 months, and expert advice from Wood Mackenzie confirms this. Beyond 24 months, LNG market participants continue to view oil-linked LNG contract prices, which are typically calculated as a percentage of oil index prices, as the key benchmark of Asian LNG prices.

There are challenges with publishing additional forward LNG netback prices using an oil index, the key of which is determining an appropriate percentage to apply to oil prices to calculate an LNG price. The ACCC will use consultant estimates of the appropriate percentage to calculate longer-term forward LNG netback prices.

5.1. Stakeholder views on the relevance of different LNG price markers

Over the course of this review, stakeholders expressed a range of views about which LNG price (or price marker) the ACCC should use to calculate LNG netback prices. Most stakeholders recommend the ACCC use either JKM or Henry Hub, although several gas suppliers also raised oil-linked LNG prices as an option for longer-term forward LNG netback prices.

5.1.1. C&I users generally want the ACCC to use Henry Hub prices

All of the C&I users and related industry bodies who provided submissions to the review support the ACCC using a more liquid reference price than JKM as a starting point for calculating LNG netback prices. In particular, C&I users suggest that the ACCC use prices at the US Henry Hub to calculate LNG netback prices, because:

- the US is becoming the marginal LNG supplier into Asia
- some of the US LNG contracts have feedgas pricing tied directly to Henry Hub
- the Henry Hub is a deep and liquid market
- Henry Hub prices are less volatile than JKM.

For example, Qenos, Incitec Pivot, Chemistry Australia and the Energy Users Association of Australia suggest that the Henry Hub will become the benchmark for Asian LNG spot prices due to the US becoming the marginal supplier of LNG into Asia.[66] EY Port Jackson Partners (EY PJP) submitted that Henry Hub prices should be used to calculate LNG netback prices because US LNG exports are forecast to continue to grow rapidly and '… the US is emerging as the price setter globally, given the US industry's size and low-cost position on the supply curve.'[67]

Qenos also notes that the US is expected to account for around half of the global gas supply growth by 2030, and that around 75% of the growth in US production will be exported.[68] The Chicago Mercantile Exchange (CME) submitted that some US LNG cargoes delivered to Japan and Korea already have pricing tied to Henry Hub and that Asian LNG spot prices are influenced by US LNG cargoes.[69]

Qenos, Incitec Pivot and Chemistry Australia support the use of Henry Hub for calculating netback prices because Henry Hub has a high degree of liquidity and prices are less volatile than JKM.[70] Most C&I users consider that an LNG netback price using Henry Hub prices would better align the LNG netback price series with international LNG markets.[71] Further, it would allow gas buyers to negotiate with domestic producers for gas supply at internationally competitive prices, as well as manage price risk through traded financial products.[72]

Chemistry Australia and Major Energy Users also submitted that short and longer-term forward netback prices could be based on the Henry Hub due to its deep and liquid market.[73] We discuss extending the forward netback beyond 2 years in chapter 3.

CME, which offers Henry Hub futures through its New York Mercantile Exchange, submitted that Henry Hub futures are the most actively traded gas futures, noting that the average daily volume of trade in Henry Hub futures reached 467,000 contracts in 2020.[74]

However, ConocoPhillips Australia submitted that the Henry Hub futures market has liquidity issues similar to the JKM futures market beyond one year. ConocoPhillips Australia

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66 Qenos, Submission to the issues paper, April 2021, p. 4; Incitec Pivot, Submission to the issues paper, April 2021, p. 5; Chemistry Australia, Submission to the issues paper, April 2021, p. 5; Energy Users Association of Australia, Submission to the issues paper, April 2021, p. 4.

67 Chemistry Australia, Submission to the issues paper (attachment), *EY Port Jackson Partners – Developing a robust domestic gas price marker*, May 2021, p. 3.

68 Qenos, Submission to the issues paper (attachment), April 2021, p. 4.

69 CME, Submission to the issues paper, April 2021, p. 4.

70 Qenos, Submission to the issues paper, April 2021, p. 2, 5; Incitec Pivot, Submission to the issues paper, April 2021, p. 1; Chemistry Australia, Submission to the issues paper, April 2021, pp. 4–5.

71 Qenos, Submission to the issues paper, April 2021, p. 5; Incitec Pivot, Submission to the issues paper, April 2021, p. 2, 5; Chemistry Australia, Submission to the issues paper, April 2021, p. 2.

72 Chemistry Australia, Submission to the issues paper, April 2021, p. 2.

73 Chemistry Australia, Submission to the issues paper, April 2021, p. 5; Major Energy Users, Submission to the issues paper, April 2021, pp. 4–5.

74 CME, Submission to the issues paper, April 2021, p. 6; Each contract is for 10,000 MMBtu, which is equivalent to 10,559 GJ.

suggests that Henry Hub futures are not actively traded beyond February 2022 even though futures contracts are listed to December 2033.[75]

C&I users also consider that additional methodological approaches, such as averaging, to account for the impact of price volatility of price markers on calculated LNG netback prices is not useful.

5.1.2. Gas producers largely support the ACCC continuing to calculate netback prices using the JKM

Queensland gas and LNG producers support the ACCC's current approach to calculating the LNG netback price series using JKM because, in their view:

- Asia is the key export market for Queensland LNG producers
- Queensland LNG is predominantly sold into Asian spot markets
- JKM is the relevant measure of Asian LNG spot prices
- JKM liquidity is high in the short term.

APPEA and the LNG producers submitted that the majority of Australia's LNG exports are sold into the Asian LNG market.[76] The LNG producers also note that any uncontracted gas not sold domestically is predominantly sold into Asian LNG spot markets (for which JKM is the relevant price marker).

ConocoPhillips Australia notes that the 3 Queensland LNG producers typically use a JKM netback price to make shorter-term decisions about whether to export uncontracted gas as LNG or supply it to a domestic buyer.[77] APPEA and APLNG consider that there is no need and no evidence to support a change to the current netback approach.[78]

S&P Global Platts, which publishes JKM price assessments, submitted that the Australian LNG producers' opportunity cost is tied to LNG prices in northeast Asia.[79] Platts also noted that:

- demand from Japan, Korea, China and Taiwan account for 95% or more of Australia's exports in any given month
- Australia's proximity to northeast Asia provides Queensland LNG producers with a freight cost advantage compared to other major LNG sellers
- Asian LNG spot price futures and associated forward curves are used to determine the oil slopes in long-term LNG contracts
- liquidity in the volume of JKM derivatives increased to around 160 Mt in 2020.

ConocoPhillips Australia submitted that the increased market depth and liquidity of JKM spot and futures supports the continued use of the JKM in calculating the netback prices.[80] GLNG considers the JKM is relevant to short-term sales as it has high trading liquidity in the first

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75 ConocoPhillips Australia, Submission to the issues paper, April 2021, p. 3.

76 APPEA, Submission to the issues paper, April 2021, p. 4, 17, 21; ConocoPhillips Australia, Submission to the issues paper, April 2021, p. 3; GLNG, Submission to the issues paper, April 2021, p. 12; Santos, Submission to the issues paper, April 2021, p. 2; Shell, Submission to the issues paper, April 2021, pp.7–8; APLNG, Submission to the issues paper, p. 2.

77 ConocoPhillips Australia, Submission to the issues paper, April 2021, pp. 1–2.

78 APPEA, Submission to the issues paper, April 2021, p. 3; APLNG, Submission to the issues paper, April 2021, p. 2.

79 S&P Global Platts, Submission to the issues paper, April 2021, pp. 1–2, 4.

80 ConocoPhillips Australia, Submission to the issues paper, April 2021, p. 2.

year.[81] GLNG and Shell also note that a JKM-based netback price series should be limited to a forward period of 2 years.[82]

Similarly, Senex submitted that the current approach to calculating LNG netback prices represents the most appropriate approach, however note the limited relevance of the netback price series to non-LNG domestic producers.[83]

The Energy Users Association of Australia suggests that the ACCC use both JKM and Henry Hub prices to calculate LNG netback prices, noting that JKM is currently a more important price setter for the domestic market, but that Henry Hub is rapidly becoming the benchmark for LNG spot sales as the US becomes the marginal supplier into LNG markets.[84]

Conversely, gas and LNG producers submitted that gas prices at the Henry Hub should not be used for calculating LNG netback prices in the east coast gas market. This is because:

- the US has not acted as the marginal supplier into Asia
- JKM already accounts for the influence of US LNG
- Henry Hub prices are reflective of local supply-demand conditions
- gas production costs in the US are significantly lower than in the east coast gas market.

For example, APLNG submitted that the US did not act as the marginal supplier of LNG into Asia to mitigate the spike in JKM prices in mid-January 2021.[85] APLNG suggests that shipping constraints and supply-side issues were factors which limited the US's ability to respond to a tightening Asian LNG market. APLNG also notes that, in its experience, Asian LNG buyers do not purchase spot LNG on a Henry Hub linked basis.

GLNG, Santos and Origin submitted that to the extent that Henry Hub and other price makers are relevant for Asian LNG prices, these factors would already be reflected in JKM prices.[86] Origin notes that JKM captures offers made by international LNG producers that supply LNG into Northeast Asia.[87]

Further, Origin submitted that using a price marker other than JKM, such as Henry Hub, would not be reflective of actual LNG deliveries into Asia.

Shell considers that prices at the Henry Hub reflect local US demand and supply dynamics, including low gas production costs due to co-production with other liquids, and note that US dynamics are unrelated to Asian LNG markets conditions.[88] APLNG also notes that the spike in Henry Hub spot prices in February 2021, due to extreme weather conditions in southern US states, did not impact on Asian LNG spot prices.[89]

Shell suggests that should the ACCC decide to publish longer-term forward LNG netback prices, then using oil-linked LNG contract prices may be the preferable approach. Specifically, Shell proposes that the ACCC uses an oil-linked 'slope' applied to Brent futures quoted by ICE, with forward LNG freight cost estimates sourced from a consultant. However, Shell notes some challenges and considerations of using this type of approach, including:

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81 GLNG, Submissions to the issues paper, April 2021, p. 11.

82 ibid; Shell, Submission to the issues paper, April 2021, p. 4.

83 Senex, Submission to the issues paper, April 2021, p. 3.

84 Energy Users Association of Australia, Submission to the issues paper, April 2021, p. 4.

85 APLNG, Submission to the issues paper, April 2021, p. 4.

86 GLNG, Submission to the issues paper, April 2021, p. 11; Santos, Submission to the issues paper, April 2021, p. 2; Origin, Submission to the issues paper, April 2021, p. 1.

87 Origin, Submission to the issues paper, April 2021, p. 1.

88 Shell, Submission to the issues paper, April 2021, p. 7.

89 APLNG, Submission to the issues paper, April 2021, p. 4.

- whether imported LNG prices are more relevant in the longer term
- that while Brent oil futures are readily accessible and transparent, they are a price for a futures contract, not a forecast price for oil.

Further, APLNG notes that the east coast gas market and the Henry Hub are not physically connected, and that domestic gas users are not able to access gas sourced from the Henry Hub because Australia does not have an import terminal.[90] Origin also notes that Australian LNG producers are not able to access Henry Hub prices by delivering gas into the Henry Hub due to the US not having LNG import terminals.[91]

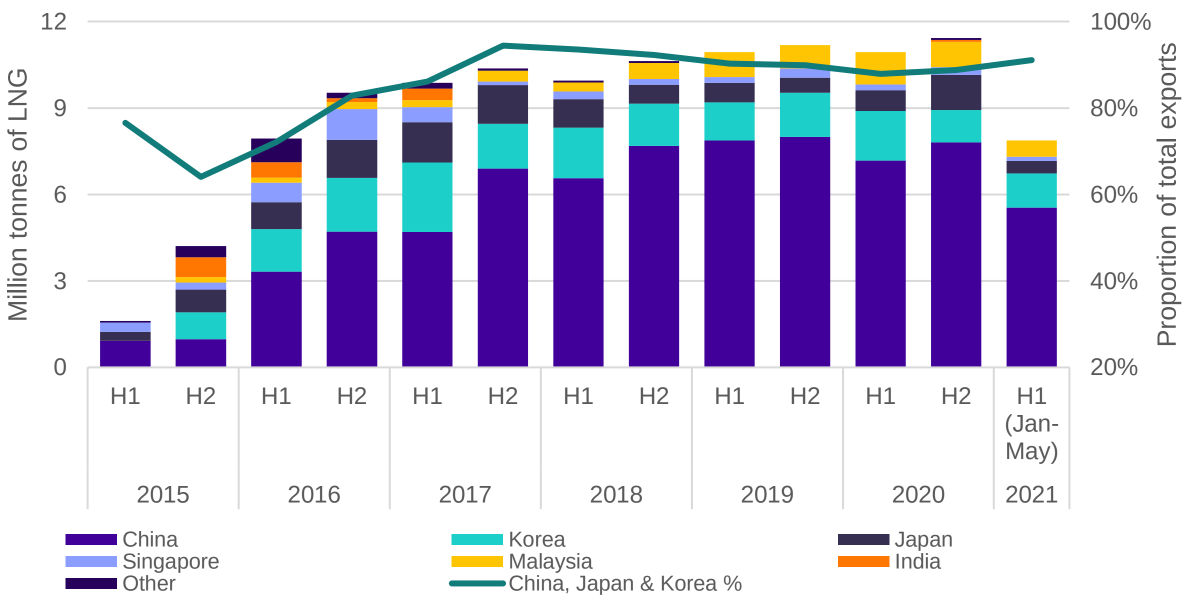
While stakeholders have differing views about the current influence of Henry Hub on Asian LNG spot prices, there was some consensus that Henry Hub could be a future driver of Asian LNG prices. Should this occur, Henry Hub prices may be an appropriate reference price for calculating LNG netback prices. APLNG, ConocoPhillips Australia and Shell consider a review of the netback price series may be appropriate following the expansion of the Qatar and US LNG facilities expected by 2023-24.[92]

Gas and LNG producers also consider averaging to account for the impact of price volatility of price markers on calculated netback prices would not add any value to the netback series while also adding unnecessary complexity.

5.2. Asia is the key market for Queensland LNG exports

Since 2015, Queensland LNG producers have exported the majority of their LNG (both spot and long-term contract volumes) to northeast Asia (figure 5.1).[93]

Figure 5.1: Queensland LNG producer exports by destination, 2015 to 2021



Source: Australian Energy Regulator; ACCC analysis of Gladstone Port Corporation data.

90 APLNG, Submission to the issues paper, April 2021, pp. 4–5.

91 Origin, Submission to the issues paper, April 2021, p. 1.

92 APLNG, Submission to the issues paper, April 2021, pp. 3–4; ConocoPhillips Australia, Submission to the issues paper, April 2021, p. 5; Shell, Submission to the issues paper, April 2021, pp. 1–2.

93 Gladstone Port Corporation, *Trade statistics*, n.d., https://www.gpcl.com.au/trade-statistics, viewed 1 June 2021.

This reflects Australia's close proximity to northeast Asia, which is a major LNG importing region. In 2020, northeast Asian countries accounted for 55% of total global LNG demand.[94]

China is the largest importer of Queensland LNG, accounting for two-thirds of Queensland's LNG exports in 2020. Japan and Korea were the next largest importers of Queensland LNG in 2020, accounting for about 23% of exports.

Asia is likely to continue to be the primary destination for Queensland LNG exports in the near term and over the longer-term, as noted by Wood Mackenzie.[95] Asian LNG demand continues to grow (chapter 3) and is likely to outpace growth in Europe, which is the other major LNG importing region.

Asian LNG prices will continue to be relevant to the east coast gas market as LNG producers will continue to view LNG sales into Asia as an alternative to supplying the domestic market.

5.3. The merits of different price markers for calculating LNG netback prices

Global gas and LNG markets are becoming increasingly linked as global LNG trade grows and becomes more flexible, as noted by Wood Mackenzie in their preliminary report to the ACCC. Because of this, there are potentially several LNG and gas price markers that could be used, as a measure of Asian LNG prices, for calculating LNG netback prices in the east coast gas market.

5.3.1. Japan-Korea Marker (JKM)

JKM has emerged in recent years as a transparent price marker for LNG spot sales into northeast Asia, with JKM futures tradable on the Intercontinental Exchange (ICE).

Wood Mackenzie has provided expert advice that JKM is increasingly being accepted by LNG market participants as the benchmark for Asian LNG spot prices.

While JKM is the most commonly used as a reference for Asian LNG spot sales, it is also sometimes used in short, medium and long-term LNG contracts. For example, Santos recently entered into a 10-year JKM-linked LNG contract with Diamond Gas International (a subsidiary of Mitsubishi).[96]

JKM has also been referenced directly in domestic GSAs in the east coast gas market, albeit in only a few GSAs.[97] APLNG recently announced that it had signed a JKM-linked GSA with Origin for up to 91PJ of gas over 4 years.

LNG producers on the east coast also view JKM as a relevant benchmark for the domestic market. The ACCC's review of pricing strategy documents obtained from the LNG producers suggests that they view JKM netback as reflecting their opportunity costs of domestic supply over the short term.

Expected future growth in LNG spot trade in Asia and JKM liquidity means that it is likely that JKM will become more influential as a price marker for the Asian LNG market. JKM liquidity

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94 Shell, LNG Outlook, 2021, https://www.shell.com/energy-and-innovation/natural-gas/liquefied-natural-gas-lng/lng-outlook-2021, viewed 1 June 2021.

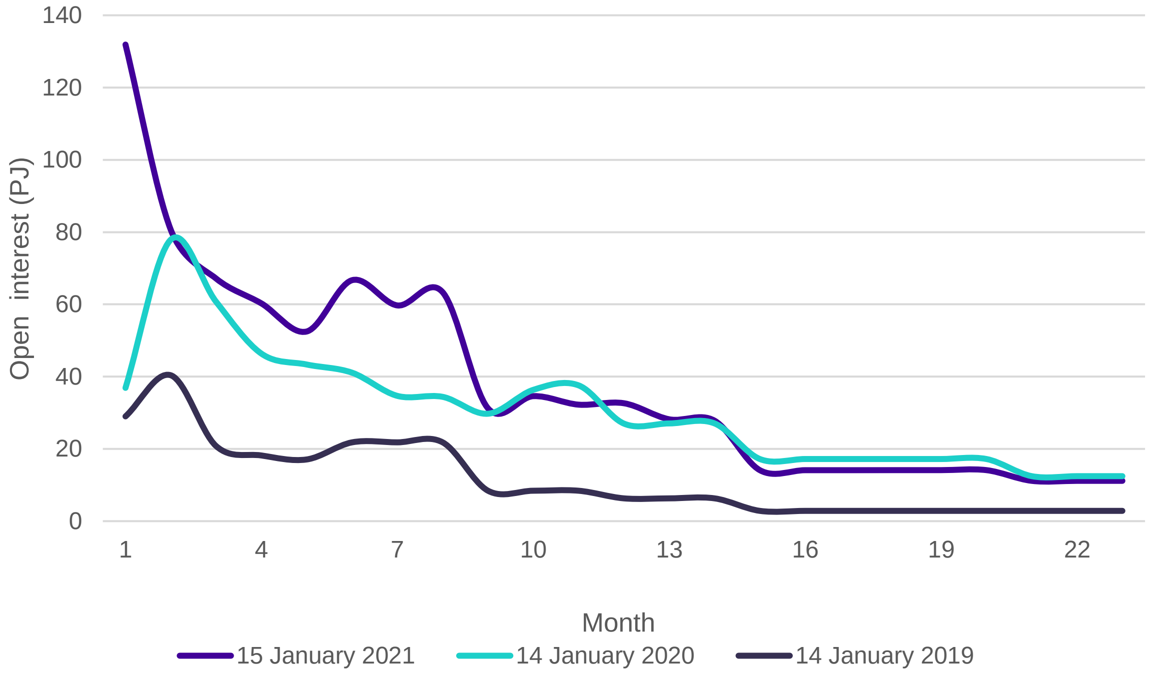
95 Wood Mackenzie, preliminary report, June 2021, p. 30.

96 Santos, *Santos, Santos and Mitsubishi sign SPA for Barossa LNG supply*, 7 December 2020, https://www.santos.com/news/santos-and-mitsubishi-sign-spa-for-barossa-lng-supply/, viewed 16 June 2021.

97 ACCC, Gas Inquiry 2017-2025 interim report, July 2020.

has grown in recent years, with annual JKM futures' traded volumes increasing from less than 10 million tonnes in 2017 to about 160 million tonnes in 2020 (figure 5.2).

Figure 5.2: Growth in JKM futures liquidity



However, a key limitation is that JKM futures have limited liquidity beyond a forward period of about 2 years, even though JKM futures are tradable out to 7 years. This prevents it from being a reliable and credible reference for calculating LNG netback prices for periods beyond 2 years.

The lack of liquidity in JKM means that it is currently unsuitable for calculating forward LNG netback prices beyond 2 years, and also limits the ability of parties to use JKM futures contracts to hedge against adverse price movements.

Some stakeholders submitted that JKM is also relatively volatile, with prices sometimes increasing significantly over short timeframes. In January 2021, JKM prices increased significantly due to colder than expected weather in northeast Asia and supply issues in Australia and Indonesia. Factors such as LNG storage levels and the availability of supply from Qatar and the US also influence JKM volatility. That said, the volatility in JKM ultimately reflects volatility in Asian LNG supply and demand fundamentals, which the east coast LNG producers face directly when deciding whether to supply uncontracted gas into Asian LNG markets.

5.3.2. **Short to medium-term oil-linked Asian LNG contract prices**

Prices in oil-linked medium-term LNG contracts, which are calculated using oil indexes, could be used to calculate LNG netback prices over a longer forward period than 2 years.

The majority of LNG sold into Asian LNG markets have prices directly linked to oil indexes, typically Brent or Japanese Crude Cocktail indexes (box 5.1).

Box 5.1: Oil-linked LNG prices

Most Asian LNG contracts are linked to oil prices via indexes such as Brent or JCC. Oil prices have historically been referenced in LNG pricing as crude oil was the biggest competing fuel source for power generation when Japan first began importing LNG in 1969. Oil-linked LNG pricing persisted as other countries began importing LNG.[98]

LNG prices linked to oil prices use either a simple percentage link or an 's-curve' formula, and are typically calculated against a rolling 3-month average of oil prices (to smooth out short-term volatility).[99, 100]

LNG market participants can prefer S-curve formulas as they minimise the impact on LNG contract prices of very low or very high oil prices. LNG slopes in long-term contracts entered into by Australian LNG producers (including those in WA and the NT) reportedly range from 12% to 15%.[101]

S-curved formulas typically take the following form:

$$\boldsymbol{Price_{LNG}} = \boldsymbol{\alpha} + \boldsymbol{\beta} \times \boldsymbol{Price_{Oil}}$$

$\boldsymbol{Price_{LNG}}$ is the price of delivered LNG in USD$/MMBtu while $\boldsymbol{Price_{Oil}}$ is a given oil index price in USD$ per barrel. $\boldsymbol{\alpha}$ and $\boldsymbol{\beta}$ are parameters that reflect transportation costs and the pricing 'slope' used to link oil indexes to LNG prices, respectively.

For example, at Brent oil prices of USD$60 per barrel, and with parameters of $\boldsymbol{\alpha} =$ USD$1 and $\boldsymbol{\beta} =$ 10%, delivered LNG prices would be USD$7/MMBtu.

An implied forward curve for LNG can be constructed by multiplying a given pricing slope by the Brent or JCC forward curve for oil (figure 4.4 presents an example of an implied forward curve for an oil-linked LNG price).

These oil-linked contracts include both long-term foundation LNG Sale and Purchase Agreements (which underpin the development of LNG plants) and short to medium-term multi-cargo LNG contracts (so-called LNG strips). Wood Mackenzie's expert advice is that LNG market participants generally view oil indexes as the appropriate benchmark for LNG strip prices, which are calculated as a percentage of the oil price.

An advantage of using oil-linked LNG strip prices is that oil indexes are deep, transparent and liquid. The level of liquidity in oil futures markets is also much higher than that in JKM, Henry Hub and TTF. This provides East Coast gas buyers with a more comparative price marker for longer duration contracts, and allows market participants to hedge against future price movements.

Wood Mackenzie notes that medium-term LNG contracts are typically priced against oil indexes. Further, Wood Mackenzie's expert advice is that oil-linked pricing is relevant to the east coast gas market as existing contracts (both LNG and some domestic GSAs) have prices linked to oil.[102]

The ACCC has seen internal documents obtained from the LNG producers that indicates they view medium-term LNG strip contracts as an alternative to supplying the domestic

98 RBA, *Australia and the Global LNG Market*, 2015, https://www.rba.gov.au/publications/bulletin/2015/mar/bu-0315-4a.html, viewed 16 June 2021.

99 This depends on whether β, the pricing slope, is non-linear.

100 Wood Mackenzie, preliminary report, June 2021, p. 33.

101 RBA, *Australia and the Global LNG Market*, 2015, viewed 16 June 2021.

102 Wood Mackenzie, preliminary report, June 2021, p. 33.

market. LNG producers view prices in such contracts as an opportunity cost of entering into longer-term domestic GSAs (with terms of more than 2 years).

An issue with using oil indexes for calculating LNG netback prices is the availability, quality and reliability of data.

A challenge of using an oil index is determining the appropriate percentage (or slope) of the oil price that determines the LNG price. This is particularly challenging due to the lack of transparency on slopes in recent LNG strip contracts, which can vary over time as LNG market conditions change.

LNG strips are traded bilaterally through contracts with confidential terms and conditions. There is no comprehensive publicly listed record of actual or current LNG contracts or price formulas. Therefore, market participants currently rely on price assessments from market analysts and research firms.

Oil-linked slopes can also differ between LNG strip contracts depending on a range of factors such as flexibility in delivery terms, volumes, and seasonality. Some stakeholders suggest that using oil indexes to calculate LNG netback prices would require a degree of normalisation to account for these factors.

Another challenge relates to whether oil futures accurately reflect market expectations around future oil prices. Some stakeholders submitted that oil futures prices are not necessarily forecasts of future oil prices.

However, Wood Mackenzie advises that oil indexes present a suitable alternative for calculating forward LNG netback prices for periods beyond 2 years (applying slopes in medium-term LNG strips). This is because LNG strips are predominantly priced with reference to oil prices. Domestic LNG producers also consider oil-linked LNG strip prices when forming views about domestic prices (which in turn influence the prices they offer for gas supply).

5.3.3. **Henry Hub**

C&I users support the ACCC using Henry Hub prices for calculating the LNG netback price series.

The Henry Hub is a gas distribution point located in the southern United States. It is a highly transparent and deeply liquid pricing hub and is connected to 9 intrastate pipelines and 4 interstate pipelines.[103]

Henry Hub also has a well-traded futures market (it is also the delivery point for Henry Hub natural gas futures traded on the New York Mercantile Exchange). Henry Hub futures are tradable out to 2031, although open interest in Henry Hub futures falls to zero after about 7 years.

This liquidity provides information on future pricing trends and allows market participants to hedge against adverse price movements. The level of liquidity in Henry Hub also far outweighs that in both the TTF and JKM.

The Henry Hub is directly used as a pricing mechanism by some of the US LNG projects. These projects sell LNG on a Free On Board basis and without destination clauses, which means that the LNG buyers have the flexibility to supply into different LNG markets. In

[103] AER, *Wholesale markets quarterly report*, 17 May 2021, https://www.aer.gov.au/wholesale-markets/performance-reporting/wholesale-markets-quarterly-q1-2021, viewed 16 June 2021.

practice, these buyers (who are typically traders) arbitrage between different LNG import markets based on price differentials between those markets.

Future growth in US liquefaction capacity has the potential to increase the influence of Henry Hub prices on global LNG prices, particularly in Asia, which is likely to see the majority of future LNG demand growth.

There are significant limitations, however, with using Henry Hub prices to calculate LNG netback prices in Australia.

Asia is Australia's key export market, and while Henry Hub pricing can influence the supply of US LNG into other markets, including Asia, there are other factors that also influence demand and supply dynamics in Asia. As noted by Wood Mackenzie, US Henry Hub-linked LNG is only one source of LNG supply into the Asian market. US LNG producers seeking to supply into Asia need to compete with LNG producers from other regions, particularly Australia and Qatar.

Portfolio players who are able to manage destination flexibility and arbitrage between Europe and Asia will generally have more appetite, than other LNG buyers, to enter into Henry Hub-linked LNG contracts. However, they are likely to on sell into Europe or Asia at either TTF or JKM prices, depending on which destination offers a higher return. This is because US Henry Hub-linked LNG prices are Free On Board prices rather than delivered LNG prices.

The majority of US LNG is also shipped into European markets, rather than Asia, as shipping distances to Europe are significantly shorter. Due to this, the proportion of Henry Hub-linked LNG that is delivered into Asia remains relatively small.

Australia is also not directly connected to Henry Hub. Australian C&I users are not able to source gas from Henry Hub as Australia does not have the ability to import LNG. Domestic LNG producers are also not able to export gas to the US, and for this reason Henry Hub prices are best described as an indirect and imperfect measure of the opportunity cost of supplying gas to the east coast gas market.

Given its location, Henry Hub is ultimately a price marker for the US market rather than LNG markets. This is because Henry Hub prices are significantly influenced by domestic US demand and supply dynamics, with LNG exports accounting for only 10% of US gas production.

There may be periods in which Henry Hub prices are aligned with Asian LNG prices such as JKM. However, as noted by Wood Mackenzie, JKM and Henry Hub prices are for the most part not correlated, and there are factors that influence Asian LNG prices which are not reflected in Henry Hub prices (figure 5.3).

Figure 5.3 presents a regression of JKM prices on Henry Hub prices. The measure of fit for the regression (R^2) suggests factors other than Henry Hub have a larger influence on JKM prices.[104]

One of these factors is TTF prices, which Wood Mackenzie suggest may play a larger role in influencing Asian LNG prices, and which is more correlated with JKM than Henry hub is (as shown in figure 5.4).

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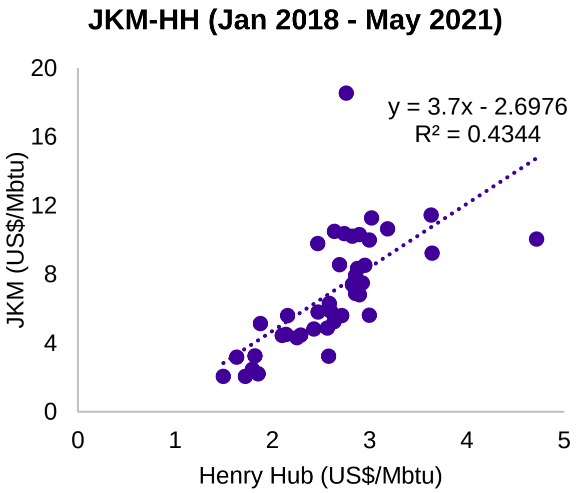
[104] R^2 is a measure of how well an econometric regression model fits the data. In this case, it is a measure of how well changes in Henry Hub prices explain changes in JKM prices. R^2 is expressed as a percentage from 0-100%, with higher numbers indicating a better measure of fit.

Figure 5.3: Relationship between JKM and Henry Hub since 2018



Henry Hub prices may have greater influence on Asian LNG prices in the future as US LNG export volumes into Asia grow. However, it is not clear when this may occur or how much influence it may have.

Therefore, while we do not consider Henry Hub to have a strong or dominant influence on Asian LNG markets, this may change in the future and is one of the reasons we will undertake a public review of the LNG netback price series in 2024.

5.3.4. **Title Transfer Facility (TTF)**

The TTF price marker is another reference price that could be used to calculate LNG netback prices. The TTF is virtual trading hub for physical gas and gas futures located in the Netherlands.

Although no C&I users directly recommend the ACCC use TTF prices to calculate LNG netback prices, it is a deeply traded and transparent market price, and is an accepted benchmark for LNG prices in Europe (with LNG prices being TTF minus regasification costs).[105] Unlike Henry Hub prices, TTF prices are a proxy for LNG prices.

TTF also has a deep futures market relative to JKM, which, similar to Henry Hub, allows market participants to hedge against future price movements.

Europe plays a key role in balancing world LNG markets, acting as a buyer of last resort. This reflects both Europe's large demand and extensive gas storage capacity. In periods of low LNG prices, European buyers act to absorb 'excess' LNG volumes, in part to increase gas storage levels. By acting as the buyer of last resort, European prices, specifically TTF, act to set a floor price for LNG prices including in Asia. Platts notes the role that TTF plays in setting a floor for its JKM price assessments.[106]

Wood Mackenzie notes that Asian LNG prices are likely to be more closely aligned with TTF than with Henry Hub. Europe is relatively close to Qatar and the United States, which are major LNG exporters. This means that, at times, Asian LNG buyers need to offer prices in

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105 Wood Mackenzie, preliminary report, June 2021, p. 31.

106 S&P Global Platts, *Specifications guide, Liquefied natural gas assessments and netbacks*, April 2020, https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/lngmethodology.pdf, viewed 16 June 2021.

line with TTF (adjusting for LNG freight cost differences) to incentivise LNG suppliers to redirect LNG cargoes towards Asia.

However, a limitation with using TTF prices to calculate LNG netback prices for the east coast gas market is that TTF prices do not reflect Asian LNG market fundamentals.

Rather, European demand and supply dynamics are the driver of TTF prices, and these dynamics are different from those in Asia. While European LNG market dynamics are influenced by broader LNG supply into Europe (which can be impacted by the level of supply of LNG to Asia), they are also influenced by European-specific factors. In particular, pipeline gas supply from Norway and Russia have a large influence on TTF prices, with Russian pipeline flows also being influenced by political considerations.

European environmental policies and economic activity can also impact materially on the level of European demand for gas, and therefore on TTF prices.

While TTF prices and JKM prices are sometimes correlated, this is not always the case, and Wood Mackenzie notes that there are factors that influence Asian LNG prices which are not reflected in TTF prices (figure 5.4).

Figure 5.4: Relationship between JKM and TTF since 2018

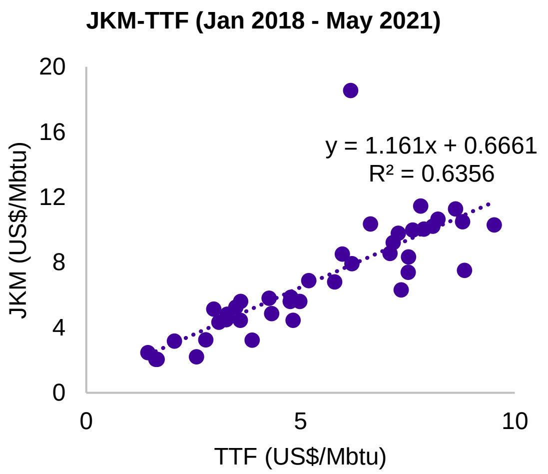

Figure 5.4 presents a regression of JKM prices on TTF prices. The measure of fit for the regression (R^2) similarly suggests that factors other than TTF prices have a larger influence on JKM prices. Wood Mackenzie notes that fundamentals in the European gas and Asian LNG markets can quickly result in prices in each market diverging.

Finally, using TTF prices as a proxy for Asian LNG prices would require adjusting for LNG freight costs between Europe and northeast Asia. These costs can be volatile and vary significantly over time. This presents a practical challenge to using TTF prices.

5.4. Asian LNG prices should be used to calculate LNG netback prices

The ACCC's draft decision is that Asian LNG prices should be used to calculate LNG netback prices in the east coast gas market.

5.4.1. **Asian prices best measure LNG producer opportunity cost**

Asia is, and will continue to remain, Australia's key LNG export market. This reflects Australia's close proximity to Asia and that the majority of future LNG demand growth is expected to come from Asia.

LNG prices in the Asian market, such as JKM or oil-linked LNG strip prices, are the best measure of future Asian LNG demand and supply dynamics. Prices in other regions, such as the US and Europe, can influence Asian LNG prices by influencing the supply of LNG into Asia. This integration between different markets, as discussed in chapter 3, supports the use of Asian LNG prices. In practice, this integration means that the influence of prices in other markets would already be accounted for in Asian LNG prices, to the extent that they influence demand and supply dynamics in Asian LNG markets.

The Queensland LNG producers' opportunity cost of supplying uncontracted gas to the domestic market is almost exclusively LNG exports into Asia (and northeast Asia in particular) at Asian LNG prices.

Over the short-term, this opportunity cost is reflected by JKM as a measure of Asian LNG spot prices. Beyond a period of about 2 years, this opportunity cost is best reflected by oil-linked LNG strip prices.

The ACCC's examination of pricing strategy documents obtained from the LNG producers under compulsory information notices confirms that LNG producers view:

- JKM as the relevant benchmark for shorter-term GSAs (up to 2 years)
- Oil-linked LNG strip prices as the relevant benchmark for longer-term GSAs (beyond 2 years).

However, LNG markets are dynamic and will continue to evolve as new LNG liquefaction capacity is developed. The expected growth in US LNG exports in coming years could increase the influence of Henry Hub on Asian LNG prices, particularly over a longer-forward period.

The ACCC will review the LNG netback price series again in 2024, recognising that continued evolution of LNG markets could have implications for LNG pricing dynamics and their effect on the east coast gas market.

5.4.2. **JKM should be used for short-term forward LNG netback prices**

The ACCC's draft decision is to continue to publish historical and short-term forward LNG netback prices extending to 2 years using JKM spot prices (consistent with our current approach)

Specifically, we propose to continue using JKM to publish:

- monthly historical LNG netback prices
- short-term forward LNG netback prices, presented on a monthly basis, over a period of 2 years into the future.

This is because LNG market participants view JKM as the key benchmark price for Asian LNG spot prices. Unlike Henry Hub or TTF prices, JKM reflects Asian LNG spot market demand and supply dynamics, rather than those of the European or US gas markets.

JKM is also transparent, with futures tradable over several years into the future.

JKM liquidity continues to grow as the level of LNG spot trade increases. The ACCC will monitor the level of liquidity in JKM and extend the JKM-based short-term forward LNG netback price series when feasible. The ACCC will also review the continued use of JKM as part of a subsequent ACCC review of the LNG netback price series in 2024.

5.4.3. Oil-linked LNG prices should be used to calculate longer-term forward LNG netback prices

Our draft decision is to also publish longer-term forward LNG netback prices extending to 5 years using oil indexes, in addition to our current LNG netback price series.

Over the longer-term, the key alternative for LNG producers to supplying the domestic market is to enter into oil-linked LNG strips. Given that prices in these contracts are calculated using oil prices, the most suitable reference for calculating longer-term forward LNG netback prices is an oil index.

This will require estimates of an appropriate slope to apply to an oil index to calculate an LNG price. There are challenges around the availability, quality and reliability of data on slopes in LNG strips, which are bilateral and confidential.

The ACCC will source an estimate of the appropriate slope from an expert consultant or market analyst no less frequently than on an annual basis. This slope will be applied to an oil index to calculate longer-term forward LNG netback prices over a 5 year period.

Publishing longer-term forward LNG netback prices will add transparency to the market and address an existing information asymmetry between C&I users seeking GSAs for longer than 2 years and those suppliers who already consider oil-linked LNG prices when forming views about domestic prices. As noted in chapter 4, C&I users often seek GSAs for terms of longer than 2 years.

However, there are also potential risks associated with this approach. Publishing longer-term forward LNG netback prices could result in these prices becoming a de facto market price floor, particularly in periods where oil-linked LNG netback prices are higher than those based on JKM.

This risk is largely caused by the lack of certainty and transparency around some key inputs used in calculating the longer-term forward LNG netback prices, in particular the slope. As a result, there is a risk that the ACCC’s long-term forward LNG price series may differ from the actual commercial alternatives available to the LNG producers when deciding whether to enter long-term domestic GSAs. This is likely to be of particular concern if the ACCC’s long-term forward LNG prices are above the prices that LNG producers could actually achieve in exporting gas. For example, this could occur if the ACCC publishes longer-term forward LNG netback prices based on a slope that is above the slope underpinning longer-term export contracts that are available to LNG producers. In such a case, there is a risk that the LNG producers will treat the ACCC’s LNG netback prices as price floor in negotiations with domestic buyers, resulting in domestic gas prices that are higher than they otherwise would have been the case.

It is not clear how material these risks are, or whether they would be outweighed by the benefits of additional transparency. On balance, our preliminary view is that publishing longer-term forward LNG netback prices, using an oil index, is likely to have a net benefit for the east coast gas market by reducing a key information asymmetry between producers and C&I users when negotiating long-term contracts.

We seek feedback on the proposed approach to publishing longer-term forward LNG netback prices and the potential materiality of risks involved.

5.4.4. The ACCC proposes to maintain the current approach to converting LNG prices and freight costs to Australian dollars

As discussed in the issues paper, the ACCC sought stakeholders views on whether the current approach to converting LNG prices and LNG freight costs from USD$/MMBtu to AUD$/GJ remains fit-for-purpose.

General feedback from stakeholders suggests that the ACCC's current approach remains appropriate. As such, the ACCC proposes to retain the current approach.

The ACCC seeks feedback on any of the following issues. Where possible, please include supporting information, data and specific examples in your responses.

5. Is the ACCC's draft decision to continue using JKM to publish historical and short-term forward LNG netback prices appropriate?
6. What is the minimum level of liquidity needed in JKM futures to extend the current forward LNG netback price beyond 2 years?
7. Is the ACCC's draft decision to use prices in medium-term oil-linked LNG contracts to calculate additional longer-term forward LNG netback prices appropriate? Should the ACCC publish additional longer-term forward LNG netback prices based on oil-indexes?
8. Is the ACCC's draft decision to use consultant estimates of an appropriate percentage, or slope, of the oil price to calculate longer-term forward LNG netback prices appropriate?
9. What other issues should be considered in calculating shorter and longer-term forward LNG netback prices?

6. Export costs deducted to calculate the LNG netback price series

The ACCC calculates LNG netback prices by taking the price that LNG producers can expect to receive for supplying uncontracted gas to overseas buyers and deducting any costs that are incurred to export that uncontracted gas. These export costs are:

- LNG freight costs to ship LNG from Gladstone to northeast Asia
- Liquefaction costs to convert gas to LNG
- Pipeline transportation costs.

ACCC's draft decision

Our draft decision is to:

- maintain our current approach to deducting liquefaction and pipeline costs
- maintain our current approach to calculating historical LNG freight costs and forward LNG freight costs for periods up to 2 years
- source estimates of longer-term forward LNG freight costs from an expert consultant or market analyst no less frequently than on an annual basis.

We deduct only the costs the LNG producer incurs when supplying uncontracted gas to Asian export markets, and which are avoided if the LNG producer instead chooses to supply the uncontracted gas to the domestic market.

We do not deduct fixed costs, such as the sunk capital costs incurred in developing the Queensland LNG projects, as these costs would be incurred whether LNG producers export LNG or supply gas to the domestic market. This is discussed further in chapter 2.

Deducting only avoidable (marginal) export costs in calculating the LNG netback price series remains appropriate. This approach ensures the LNG producer is indifferent to supplying uncontracted gas to the domestic market or to LNG export markets.

Wood Mackenzie's expert advice is that deducting only short-run marginal costs is appropriate given the LNG projects continue to have spare capacity.[107]

Our draft decision is to maintain our current approach to calculating export costs. However, an alternative source of LNG freights cost estimates will be needed to publish longer-term forward LNG netback prices. There are several possible alternatives. Our draft decision is to source longer-term LNG freight cost estimates from an expert consultant or market analyst no less frequently than on an annual basis.

We are seeking feedback on our draft decision.

6.1. Stakeholder views on export costs

Stakeholder submissions on export costs predominantly focussed on whether liquefaction costs should include LNG plant capital costs, and whether pipeline transportation costs should include pipeline capital costs.

[107] Wood Mackenzie, preliminary report, June 2021, p. 50.

6.1.1. C&I users want LNG plant capital costs deducted

In our issues paper, we asked stakeholders whether our current approach to deducting liquefaction costs is appropriate and whether different approaches should be used for calculating short and longer-term LNG netback prices.

C&I users suggest that the ACCC include LNG plant capital costs when estimating liquefaction costs because the Queensland LNG projects already recover these costs via the long-term foundation offtake LNG contracts intended to help finance the construction of the LNG plants.[108] They further suggest that by not deducting LNG plant capital costs, the LNG netback price series allows LNG producers to recover LNG plant capital costs from domestic gas buyers. Chemistry Australia, for example, said that '… the current methodology includes a significant component or allowance for the capital costs of the LNG projects.'[109]

C&I users also note that deducting capital costs would significantly lower LNG netback prices. Incitec Pivot estimate that deducting the LNG plant capital costs would lower LNG netback prices by about $2.70/GJ.[110]

C&I users also express concern about the market power of suppliers and competition in the domestic market.[111] Qenos suggests the ACCC's short-run approach to calculating LNG netback prices allows producers to recover LNG plant capital costs from domestic consumers due to the high concentration of the LNG industry and its vertical integration into gas production.[112]

Along with deducting capital costs, Chemistry Australia, Qenos and Incitec Pivot also recommend the ACCC update the liquefaction cost assumptions used to calculate the LNG netback price series with the latest available data.

6.1.2. Gas suppliers support the current approach to estimating liquefaction costs

Gas suppliers broadly support the ACCC's current approach to estimating LNG liquefaction costs. The Australian Petroleum Production and Exploration Association (APPEA), the industry body for gas suppliers, notes that the ACCC's current approach to deducting avoidable costs is consistent with the opportunity cost concept that underpins LNG netback pricing.[113] Further to this, APPEA specifically suggests that it is appropriate to not deduct any of the capital costs incurred to develop the LNG projects.

The Queensland LNG producers note that the capital costs of building the LNG plants do not factor into their decisions on which markets to supply. For example, APLNG said that it '… does not specifically seek to recover [LNG plant capital costs] via LNG spot cargoes' and notes that doing so would mean APLNG is priced out of LNG spot markets (given other LNG suppliers would be willing to sell LNG into spot markets at prices reflective of their short-run marginal costs).[114]

GLNG similarly notes that its capital costs, as well as operating costs, are fixed and do not change whether uncontracted gas is sold into the domestic market or LNG export markets.

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108 Major Energy Users, Submission to the issues paper, April 2021, p. 3; EUAA, Submission to the issues paper, April 2021, p. 10.

109 Chemistry Australia, Submission to the issues paper, April 2021, p. 2.

110 Incitec Pivot, Submission to the issues paper, April 2021, p. 2.

111 EUAA, Submission to the issues paper, p. 10.

112 Qenos, Submission to the issues paper, April 2021, pp. 6–7.

113 APPEA, Submission to the issues paper, April 2021, p. 17.

114 APLNG, Submission to the issues paper, p. 2.

More specifically, GLNG suggests that more than 99% of their LNG plant operating costs are fixed, and that the incremental costs of additional LNG cargoes are negligible.[115]

Shell noted that deducting sunk capital costs from LNG netback prices would mean that gas suppliers would no longer be indifferent between supplying gas to the domestic market or to LNG export markets.[116]

Senex also suggests that there is no economic rationale for deducting sunk capital costs, noting that these costs are not factored into Asian-focused LNG markets (such as JKM).[117]

6.1.3. C&I users want pipeline capital costs included in pipeline transportation costs

Similar to their recommendations on LNG plant capital costs, some C&I users recommend the ACCC include pipeline capital costs in estimating pipeline transportation costs.

Incitec Pivot recommend the ACCC deduct all pipeline capital costs and charges between Gladstone and Wallumbilla when calculating LNG netback prices.[118] Qenos considers capital costs for pipeline transportation to the Gladstone LNG facilities should be referenced in the LNG netback calculation methodology. The MEU suggests that gas transportation costs to Gladstone are fixed as the LNG producers have long-term gas transportation agreements in place for these pipelines.

Additionally, Qenos notes that the ACCC pipeline transportation estimate of $0.04/GJ is low compared to Energy Quest's estimate of approximately $0.28/GJ for pipeline transportation to Gladstone. Qenos considers this difference is due to the ACCC approach not accounting for pipeline capital costs.[119]

6.1.4. Gas suppliers support the current approach to estimating pipeline transportation costs

A small number of gas suppliers support our current approach to deducting pipeline transportation costs while most others did not comment on the issue.

Shell and Origin both note that our current approach is appropriate since LNG netback prices should exclude long-term (sunk) capital costs.[120]

GLNG further notes that additional compression is required to transport gas to the domestic market, compared to the compression required to transport gas to the LNG plants, and suggests the ACCC add these costs to LNG netback prices.[121]

6.2. LNG freight costs

LNG freight costs represent the costs of shipping an LNG cargo from the loading port to the destination port.

LNG freight costs predominantly consist of vessel charter costs. Charter costs reflect the cost of chartering an LNG tanker for a round-trip voyage and may be considered either a

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115 GLNG, Submission to the issues paper, April 2021, pp. 2, 14–15.

116 Shell Australia, Submission to the issues paper, April 2021, p. 11.

117 GLNG, Submission to the issues paper, April 2021, p. 4.

118 Incitec Pivot, Submission to the issues paper, April 2021, p. 8; Qenos, Submission to the issues paper, April 2021, p. 9; MEU, Submission to the issues paper, April 2021, p. 3.

119 Qenos, Submission to the issues paper, April 2021, p. 9.

120 Shell, Submission to the issues paper, April 2021, p. 12; Origin, Submission to the issues paper, April 2021, p. 5.

121 GLNG, Submission to the issues paper, April 2021, p. 15.

sunk or avoidable cost depending on whether there is an existing term charter contract or not.

Box 6.1: Current approach to estimating LNG freight costs

Historical LNG freight costs

We use Platts' daily assessments of LNG freight costs between Gladstone and Futtsu in Tokyo Bay. These assessments are calculated in US$/MMBtu by adding together Platts' estimates of:

- Port costs incurred at the loading and discharge ports
- Charter costs for an LNG tanker over a return voyage and an assumed three-day loading/discharging period
- Boil-off costs for LNG lost during the voyage due to boil-off
- Oil fuel costs for an LNG tanker.

Forward LNG freight costs

We use Argus Media's weekly assessments of LNG freight costs between Gladstone and Tokyo. These assessments are calculated in US$/MMBtu for each of the following 24 months from the date of the estimate and comprise the same cost components incurred over a round-trip as historical freight costs, with slightly varied assumptions.

We consider LNG freight costs an avoidable cost in our LNG netback price series based on JKM, as LNG producers will generally need to charter an LNG vessel for a single voyage (spot) to supply uncontracted gas into Asian LNG spot markets. Our current approach is set out in box 6.1.

Our draft decision is that the current approach to estimating historical LNG freight costs remains appropriate, and that longer-term LNG freight cost estimates should be sourced from an expert consultant or market analyst no less frequently than on an annual basis.

We seek feedback on whether we should source longer-term LNG freight cost estimates from an expert consultant or market analyst. Alternate sources for LNG freight costs include price assessments, index-listed futures and the long-run marginal costs of a new build LNG freight vessel.

We also seek feedback on whether our current approach to calculating forward LNG freight costs for a 24-month period remains appropriate.

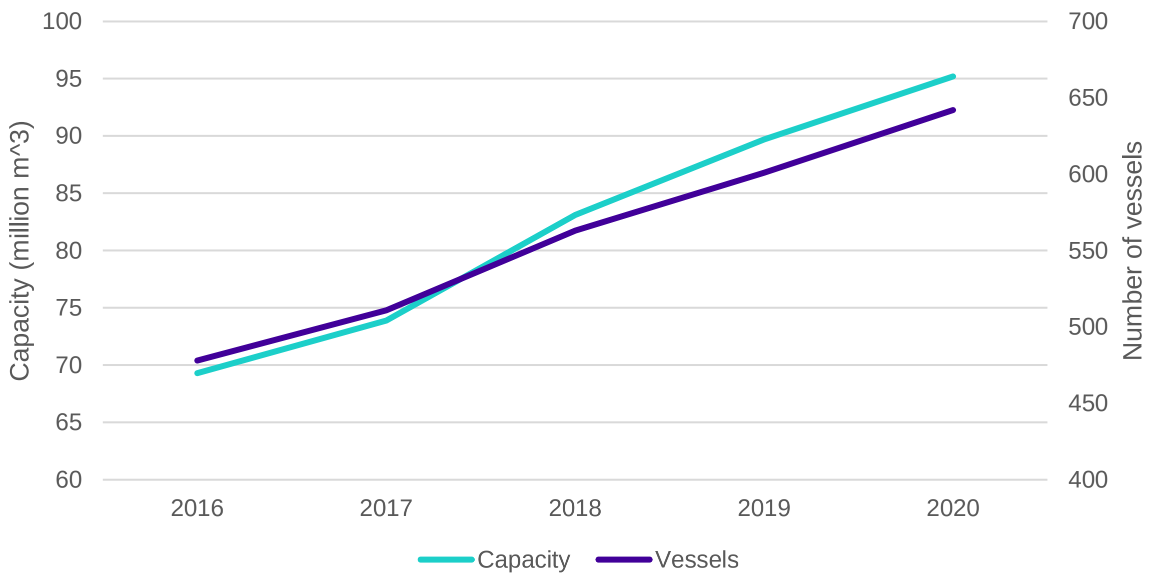
6.2.1. **Spot charter costs are an appropriate measure of short-term forward LNG freight costs**

Spot charter costs are an appropriate measure of short-term forward LNG freight costs as spot LNG freight capacity is growing and LNG producers are able to quickly access spot LNG charter markets to supply uncontracted gas as LNG to Asia.

Global spot LNG freight capacity is growing

Global LNG freight capacity continues to rapidly grow. As shown in figure 6.1, from 2016 to 2020, the number of LNG vessels increased from 478 to 642 (an increase of more than 30% on 2016 numbers). Total cargo capacity in the same period increased from 69.3 million cubic metres to 95.2 million cubic metres. This growth in expected to continue, with 72 additional vessels scheduled for delivery over 2021.[122] Approximately 20% of these vessels are without any long-term contract, which means they may be used to service LNG spot markets.[123]

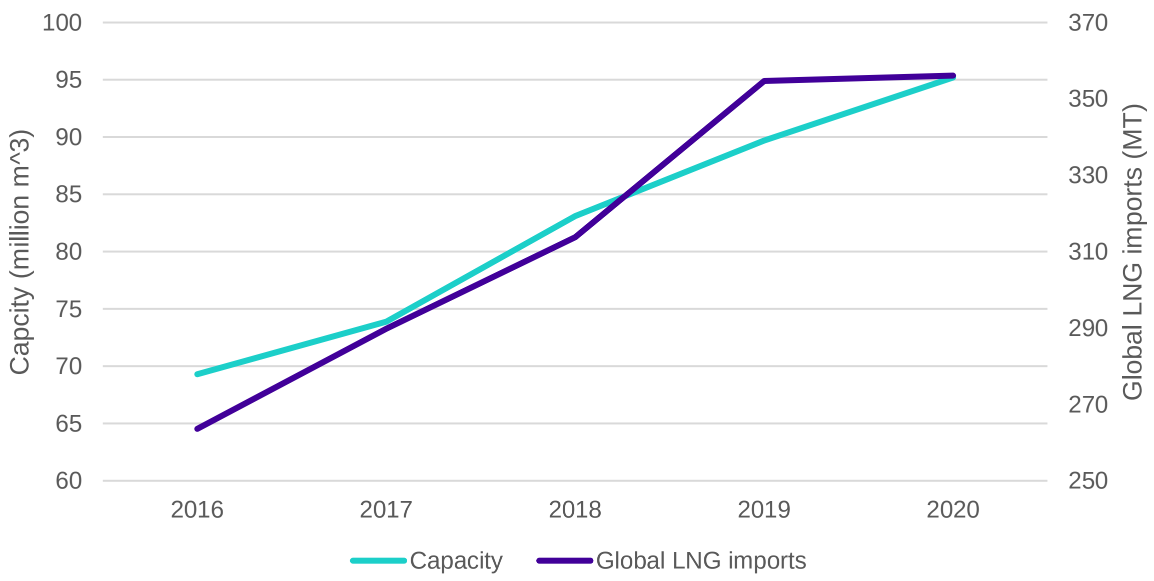
Figure 6.1: LNG freight capacity and number of LNG vessels, 2016–2020



Source: GIIGNL Annual Reports, 2017-2021

Global LNG freight capacity has increased in line with growth in global LNG trade. As shown in figure 6.2, from 2016 to 2020, global LNG imports grew by approximately 35% while global LNG freight capacity grew by approximately 37%. This trend will continue and there will be sufficient LNG freight capacity in coming years.

Figure 6.2: LNG freight capacity and global LNG imports, 2016–2020



Source: GIIGNL Annual Reports, 2017-2021

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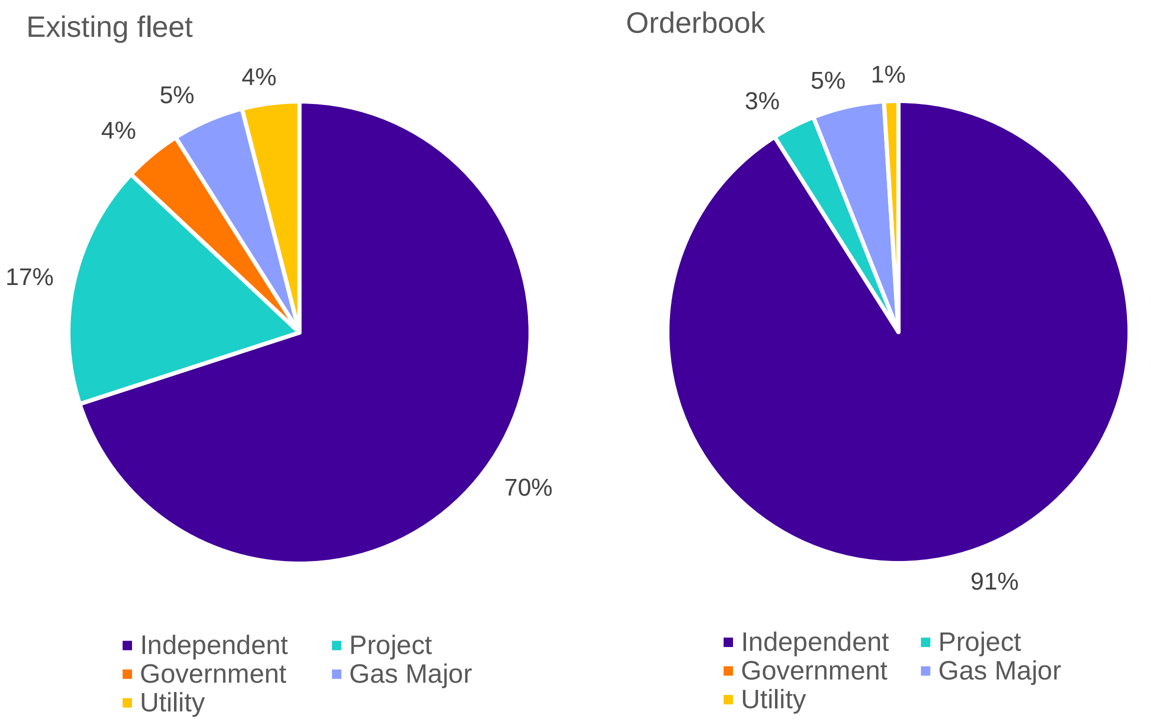
122 GIIGNL, *Annual Report 2021,* 4 May 2021, https://giignl.org/system/files/giignl_2021_annual_report_may4.pdf, viewed 29 June 2021.

123 Hellenic Shipping News, *Why are LNG shipping stocks retreating after a brief surge?,* 15 February 2021 https://www.hellenicshippingnews.com/why-are-lng-shipping-stocks-retreating-after-a-brief-surge/, viewed 29 June 2021.

The increase in LNG trade shown in figure 6.2 was primarily driven by new LNG supplies from the US and Australia, and demand growth in Asia. In 2019, the most common voyage globally was from Australia to Japan, with 447 voyages within the year.[124] As discussed in chapter 4, Asia is the key LNG export market for Australian LNG exporters.

Historically, LNG projects commissioned and operated LNG vessels to service long-term contracts. However, as LNG markets have deepened, there has been a shift in ownership to independent companies that make LNG vessels available for charter on a spot, short-term or long-term basis (figure 6.3).[125]

Figure 6.3: LNG vessel ownership, 2019



Source: Poten and Partners.

Note: An orderbook contains orders that have been made for new LNG vessels, where those vessels have not yet been delivered to the buyer.

Figure 6.3 shows that new LNG vessels will be overwhelmingly owned and operated by independent operators.

The number of LNG vessels available for spot charter fluctuates as charter contracts begin or expire. However, it is typically a small proportion of the total number of LNG vessels in the global market. In January 2021, 7% of global LNG vessels, approximately 46 vessels, were available for spot charter. This is expected to grow to 95 vessels by the end of 2021, approximately 13% of the global total.[126] This may reflect a response to growing spot LNG trade discussed in chapter 3.

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124 IGU, *2020 World LNG Report*, 27 April 2020, https://www.igu.org/resources/2020-world-lng-report/, viewed 16 June 2021.

125 Poten & Partners, *Evolution of flexibility / liquidity in the LNG shipping market*, 2019 https://www.gti.energy/wp-content/uploads/2019/10/31-LNG19-04April2019-Adede-Amokeye-paper.pdf, viewed 29 July 2021.

126 Riviera, *Five trends to watch in LNG shipping in 2021*, 28 December 2020, https://www.rivieramm.com/news-content-hub/five-trends-to-watch-in-lng-shipping-in-2021-62495, viewed 16 June 2021.

Forecasting spot charter rates beyond the short-term is difficult

Spot LNG charter rates are influenced by spot LNG vessel availability and spot LNG vessel demand.

Wood Mackenzie note the key factors that can affect carrier demand and availability, and therefore spot/short-term charter rates, are:

- Arbitrage opportunities between the Pacific and Atlantic basins
- An increase or decrease in size of the available carrier fleet due to new deliveries or decommissioning of old vessels
- Companies' trade strategies including carriers being utilised as floating storage
- Blockages and delays at either the Suez and/or Panama canals
- Variation in demand for LNG – the cyclical nature of short-term charter rates is primarily driven by variations in seasonal gas demand in European and Asian markets
- Sanctions on ship owners.[127]

In January 2021, spot LNG vessel demand increased significantly as LNG traders sought to take advantage of high prices in Asian LNG spot markets. However, this demand along with congestion in the Panama Canal (which restricted the ability of Atlantic basin LNG vessels to quickly respond to Pacific basin demand) and supply disruptions in the Pacific basin meant demand for LNG spot vessels far exceeded supply.[128] This resulted in global spot/short-term LNG charter rates reaching record levels (figure 6.4) and a temporary price spike in Argus forward freight costs estimates.

[127] Wood Mackenzie, preliminary report, June 2021, p. 39.

[128] Argus Media, *Asia Pacific LNG: Weather-driven demand boosts prices*, 31 December 2020.

Figure 6.4: Global monthly-averaged spot/short-term LNG charter rates, 2018–2021.

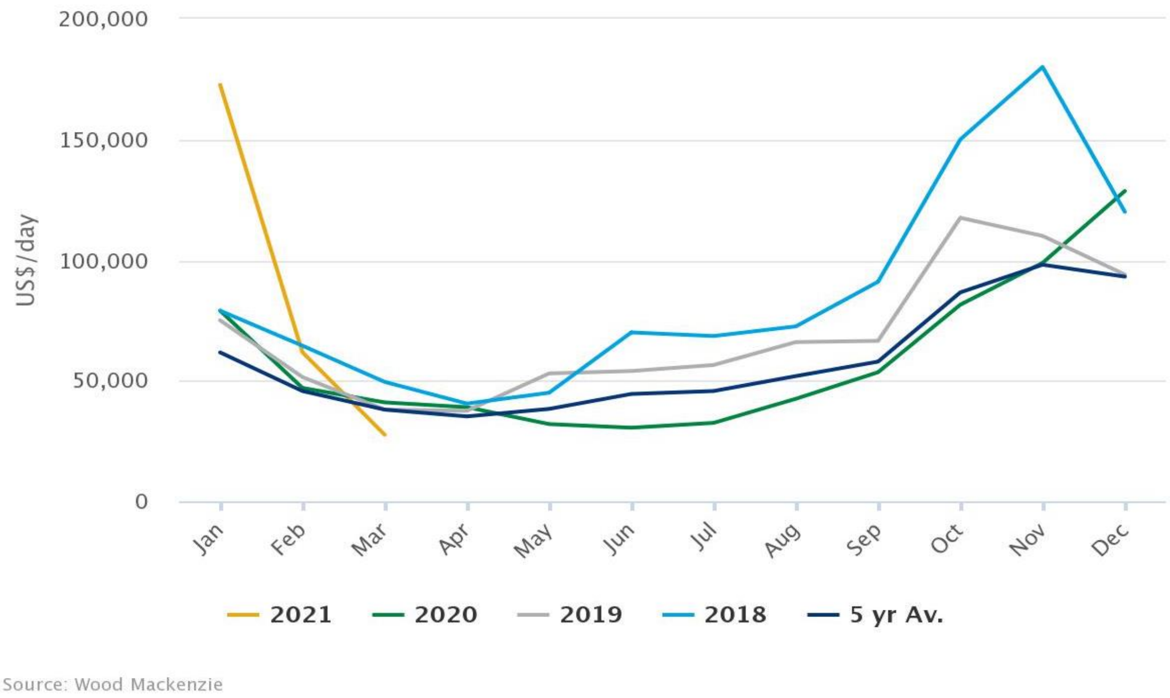
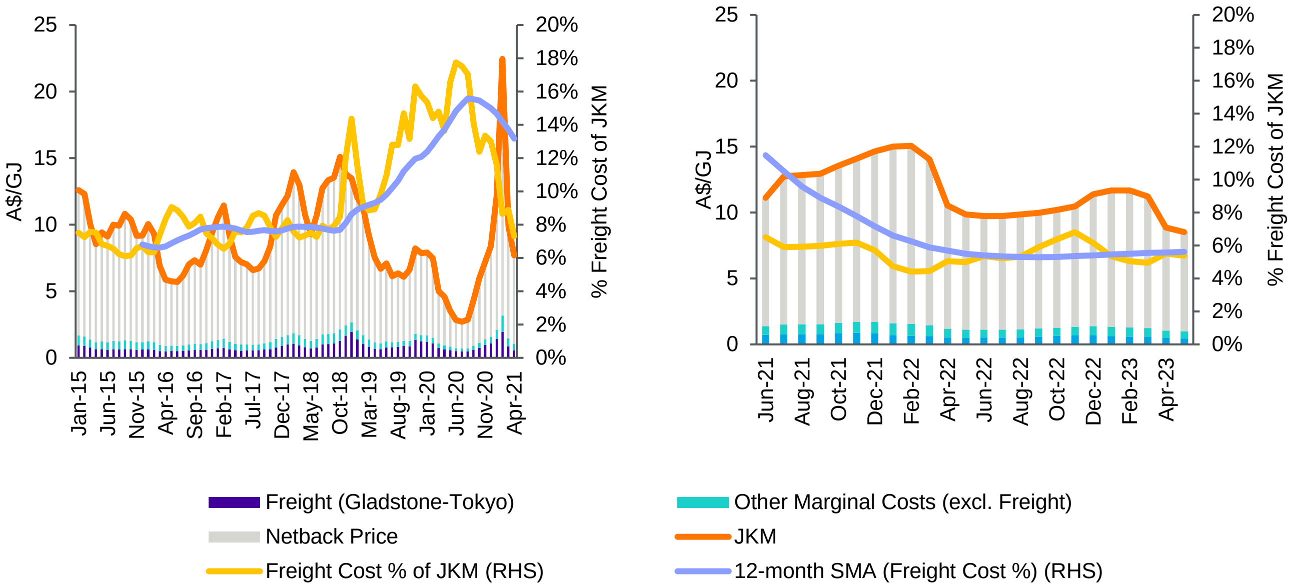


Figure 6.4 also highlights the impact seasonal demand driven by European and Asian winters has on spot/short-term LNG charter rates in the lead up into the Northern Hemisphere winter.

Wood Mackenzie expect LNG freight costs to comprise approximately 5-10% of the overall delivered LNG cost from Gladstone into Asia (figure 6.5). However, it notes temporary and structural dynamics can significantly affect the supply and demand position of the global LNG shipping fleet which results in considerable volatility in prices for short term and spot charter market. During periods of high demand and low supply LNG freight costs can account for up to 20% of the total delivered cost.

Figure 6.5: Freight cost component of the historical* and forward LNG netback price series



Note(s): * Based on Argus Media and WM's historical data (Asia LNG DES price, freight rates)

** Based on S&P Platts's forward data for JKM and freight rates (obtained via ACCC netback series); the 12-month SMAs for June 2021 – April 2022 rely on a combination of both historical data based on Argus Media & WM as well as Platt's forward curves

Source: Wood Mackenzie

Wood Mackenzie forecasts that through to 2025, an increasing amount of Atlantic LNG will be required to meet Asian LNG import demand, resulting in increasing requirements for shipping and therefore higher charter costs, particularly through winters.[129]

Overall, it appears global LNG shipping capacity will continue to grow in response to LNG trade demand, and the growing LNG spot market is resulting in increasing spot LNG vessel availability. This should place downward pressure on global LNG charter rates.

However, spot LNG charter rates can fluctuate significantly in response to various market specific LNG vessel supply and demand factors. Fluctuating demand and supply dynamics means it is especially challenging to forecast LNG charter rates beyond the 1-12 month prompt or short-term period. This has implications for our approach to estimating LNG freight costs for extended LNG netback prices.

6.2.2. Estimating forward LNG freight costs

The ACCC currently uses assessed forward LNG freight costs which are limited to a forward period of 2 years. To extend the forward LNG netback price series (discussed in chapter 3), we need to consider alternative approaches to calculating forward LNG freight costs for periods beyond 24 months.

Wood Mackenzie note that long-term freight cost forecasting (more than 2 years) depends on forming a future view of LNG market conditions, vessel fleet capacity and new-build costs (including yard availability and steel costs among others).

[129] Wood Mackenzie, preliminary report, June 2021, p. 40.

The degree of uncertainty is higher for longer-term LNG freight cost forecasts. While there is some cyclical patterning (as a result of seasonal demand), market specific supply and demand factors can result in significant fluctuations in charter rates that are difficult to predict. It is harder to anticipate these demand and supply factors over longer periods, longer-term LNG freight forecasts invariably have greater error margins than short-term forecasts.

There are several potential approaches that the ACCC could use to source or forecast LNG freight costs, each with their own benefits and limitations. We have considered the following below:

- Price assessments
- Index-listed futures
- Long-run marginal costs of a new build LNG freight vessel
- Consultant reports

Our draft decision to source longer-term LNG freight cost estimates from an expert consultant or market analyst no less frequently on an annual basis. Estimates produced by a consultant or market analyst are likely to account for a range of factors, including forecast demand and the long-run marginal costs of new LNG freight vessels.

Price assessments

We currently use price assessments provided by Platts and Argus Media to determine the historical and forward freight cost components in our LNG netback price series.

Organisations providing price assessments typically survey information provided voluntarily by market participants to determine an indicative market price of a commodity.

The price assessing organisation will typically make available its methodology for calculating price assessments so stakeholders can form their own views on the appropriateness of the methodology and the reliability of the assessed price. However, price assessments inherently rely on some form of judgement by the price assessing company in determining the commodity market value (as part of the survey process).

Along with Platts and Argus Media, submissions also highlighted the Baltic Exchange as another source of price assessments for forward LNG freight rates.[130] However, the EUAA noted that the Baltic Exchange price assessments may not be available beyond a 3 year period.

Wood Mackenzie's expert advice is that the current price assessment method for calculating historical freight costs is robust, aligned with the JKM assessment methodology and meets the transparency objectives of the LNG netback price series. We do not propose changing the current methodology for calculating historical freight costs. However, alternative approaches to estimating forward LNG freight costs may be less subjective than using price assessments.

Index-listed futures

Index-listed futures are futures contracts that can be traded today to be settled at a future date. Futures contracts are standardised and traded on regulated exchanges, meaning they are typically transparent and an efficient means of discovering a fair market price.

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[130] CME, Submission to the issues paper, April 2021; Incitec Pivot, Submission to the issues paper, April 2021; Chemistry Australia, Submission to the issues paper, April 2021; EUAA, Submission to the issues paper, April 2021.

CME notes in its submission to the issues paper that it lists LNG freight futures based on Baltic Exchange assessments on the New York Mercantile Exchange.[131]

We also note the Intercontinental Exchange (ICE) launched LNG freight futures contracts in March 2021 based on Spark Commodities's price assessments.[132]

However, index-listed futures rely on significant market activity for effective price discovery. Wood Mackenzie advises that there is no well-established LNG charter rate futures market. Currently, market activity for CME's Pacific LNG freight futures is limited and does not extend beyond 20 months.[133] Index-listed futures for LNG charter rates also reflect spot LNG charters and may not be appropriate for an extended forward netback series linked to longer-term LNG contracts. The LNG charter rate futures market may be a more appropriate mechanism to estimate short-term LNG netback prices as it becomes more liquid.

Long-run marginal costs of a new build LNG freight vessel

Given LNG trade is ultimately capped by the availability of LNG vessels, in circumstances where there is no reliable and transparent price benchmark for forward LNG freight rates, an alternative approach is to estimate the long-run marginal costs (LRMC) of building a new LNG vessel.

Estimating the LRMC of building a new LNG vessel requires an assessment of demand and cost forecasts to estimate an indicative charter day rate based upon a new build vessel. This approach would smooth the volatility apparent in short-term LNG freight estimates and reflect the approach a new LNG project developer or LNG portfolio player might consider chartering a vessel on a longer-term. However, using estimates of the LRMC of new LNG vessels as a proxy for long-term LNG freight costs assumes there is no excess LNG freight capacity, which may not be the case.

Consultant reports

Shell submitted that it primarily sources views on longer-term LNG freight rates and on the future costs of LNG vessels and technology (which sets the boil off rate/cost) from consultant reports as there are no publicly available quotes for long term LNG freight rates.[134]

The ACCC could obtain forward LNG freight rate estimates from consultants that specialise in global LNG freight cost assessments for longer-term LNG freight rate estimates. Consultant estimates may be based on propriety models underpinned by internal cost assumptions, and may already include assessments of new-build vessels costs or quotations from shipyards. Estimates may also differ between consultants depending on their views on cost assumptions.

Our draft decision is to use consultant reports to obtain longer-term forward LNG freight estimates. These estimates are likely to be available for a longer time period than those based on price assessments or index-listed futures. They will also apply when there is excess LNG freight capacity, unlike those based on the LRMC.

The ACCC seeks views and information from stakeholders on our draft decision to:

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131 CME, Submission to the issues paper, April 2021.

132 Intercontinental Exchange, *ICE Launches Spark30S Atlantic and Spark25S Pacific LNG Freight Futures Contracts, 23 March 2021*, https://ir.theice.com/press/news-details/2021/ICE-Launches-Spark30S-Atlantic-and-Spark25S-Pacific-LNG-Freight-Futures-Contracts/default.aspx, viewed 29 June 2021.

133 CME Group, *LNG Freight Route BLNG1 (Baltic) Futures*, n.d., https://www.cmegroup.com/trading/energy/freight/lng-freight-route-blng1-baltic_quotes_globex.html, viewed 16 June 2021.

134 Shell, Submission to the issues paper, April 2021.

- maintain our current approach to sourcing historical and short-term forward LNG freight costs
- source longer-term LNG freight cost estimates from a consultant no less frequently than on an annual basis.

The ACCC seeks feedback on any of the following issues. Where possible, please include supporting information, data and specific examples in your responses.

10. Is the ACCC's draft decision to use the current approach to calculating forward LNG freight costs, for period up to 24 months, appropriate? Should the ACCC use an alternative approach?
11. Is the ACCC's draft decision to use consultant estimates of longer-term forward LNG freight costs appropriate? Alternatively, should the ACCC
    (d) determine an indicative daily charter rate based on an estimate of the long-run marginal costs (LRMC) of building new LNG freight vessels
    (e) estimate the extended forward LNG freight cost based on an average of the historical or short-term forward LNG freight costs, and how should the average period be determined
    (f) estimate the extended forward LNG freight cost as a percentage of the extended forward LNG netback price, and how should that percentage amount be determined?
12. What other issues should be considered in estimating future LNG freight costs?

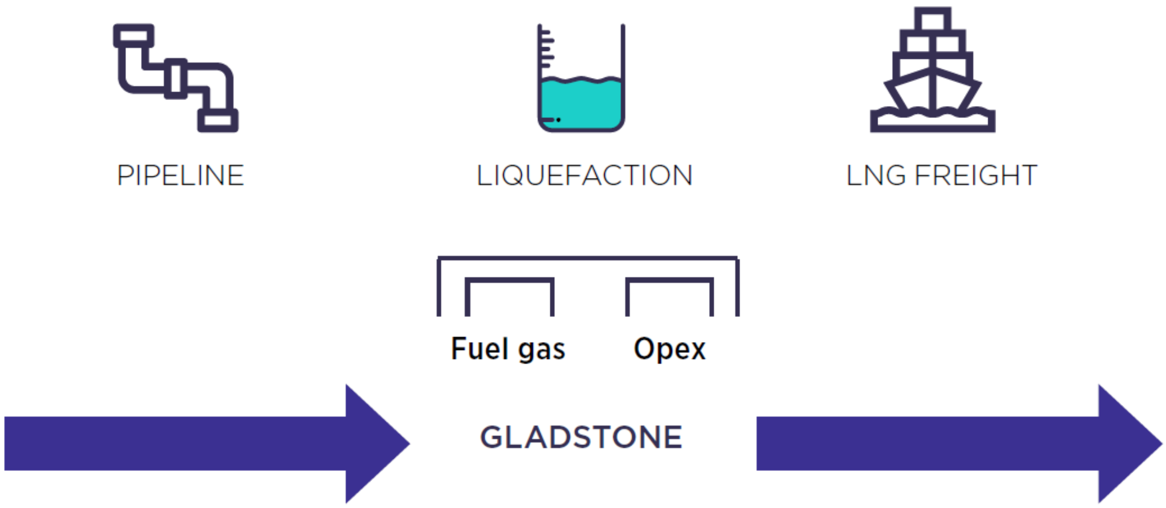
6.3. LNG liquefaction costs

LNG liquefaction costs are the costs of converting gas to LNG at the Queensland LNG plants.

The ACCC deducts 2 types of liquefaction costs to calculate LNG netback prices:

- feedgas that is used as a fuel for refrigeration and compression during the liquefaction process.
- other operating costs such as labour and electricity (figure 6.6).

Figure 6.6: Breakdown of liquefaction costs



We first deduct operating costs from our estimate of the Gladstone FOB price (discussed in section 5.2) before accounting for the gas consumed as fuel during the liquefaction process by multiplying the resulting price by the estimated marginal efficiency of the LNG plants.[135]

6.3.1. Deducting only marginal liquefaction costs remains appropriate

Our draft decision is to deduct marginal operating costs and fuel gas used in the liquefaction process when calculating LNG netback prices based on JKM. This is consistent with our current approach to estimating liquefaction costs.

LNG producers incur additional operating costs and need to use additional fuel gas to liquefy uncontracted gas for export. These costs therefore affect the net value to a producer of exporting additional uncontracted gas.

We also note that stakeholders did not provide feedback on how we currently estimate operating and fuel gas costs (other than recommending we update cost assumptions using recent data).

Wood Mackenzie's expert advice also suggests that our current approach remains appropriate. Specifically, Wood Mackenzie advises that LNG producers will only consider the marginal costs of exporting LNG when deciding whether to supply uncontracted gas to the domestic market or into export markets. Costs that cannot be avoided by not exporting, such as fixed or sunk costs, are not relevant when calculating LNG netback prices.

On this basis, our current approach to deducting liquefaction costs remains appropriate for LNG netback prices based on JKM.

As noted in chapter 3, our draft decision is to extend the LNG netback price series using an oil-linked index. To do so, we will also need to deduct liquefaction costs over a longer forward period.

Wood Mackenzie suggests that while the amount of uncontracted gas consumed as fuel during the liquefaction process could differ for longer-term forward LNG netback prices, this is unlikely to materially impact liquefaction costs.[136]

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135 The ACCC uses an estimate of the Queensland LNG plants' marginal liquefaction efficiency because this reflects the additional fuel gas required to liquefy any uncontracted gas sold as LNG.

136 Wood Mackenzie, preliminary report, June 2021, p. 59.

Our current approach to deducting liquefaction costs is therefore also appropriate for longer-term forward LNG netback prices, as the costs of liquefying uncontracted gas to service an LNG strip contract are likely to be the same as the costs of liquefying uncontracted gas for spot sales.

6.3.2. Deducting capital costs is not consistent with the opportunity cost approach

The ACCC developed the LNG netback price series as a measure of domestic producers' opportunity cost of supplying gas to the domestic market rather than LNG export markets. As noted in chapter 2, the ACCC has applied an opportunity cost framework to determine which costs to deduct when calculating LNG netback prices – in principle, this includes only those costs that need to be incurred to liquefy and export uncontracted gas.

Deducting capital costs when calculating LNG netback prices is not consistent with the opportunity cost framework that underpins the LNG netback price series. This is because these capital costs cannot be avoided at the time producers are deciding whether to supply the domestic market or export markets, which means that they do not affect the relative value of either option.

Wood Mackenzie suggests deducting capital costs would mean the LNG netback price series would no longer reflect the price at which domestic producers would be indifferent between supplying the domestic market and exporting LNG.[137] This would likely result in LNG producers selling uncontracted gas overseas rather than to domestic buyers and the LNG netback price series would no longer achieve the ACCC's objective of improving price transparency in the east coast gas market.

As noted earlier, some C&I users consider that the ACCC not deducting capital costs from LNG netback prices means they contribute, at least in part, to the recovery of LNG plant capital costs. The ACCC notes that:

- the LNG producers entered into long-term LNG Sale and Purchase Agreements (SPAs) to recover these capital costs (with these contracts containing price reviews to ensure that prices paid by LNG foundation customers are sufficient for recovery of these costs)
- the LNG netback price reflects a price which ensures that producers are indifferent between domestic supply and exporting LNG, and
- while there are periods in which LNG prices would be high enough to allow LNG producers to recover capital costs, there are also periods where LNG prices are so low that producers would not be able to do so (the middle of 2020 being an example).

Wood Mackenzie notes that while LNG spot sales may provide LNG producers with a margin in excess of their short-run costs, they do not necessarily provide a return on capital.[138]

Asian LNG prices over the short to medium term are also unlikely to account for capital costs given the number of countries completing for supply into the Asian LNG market. Attempts made by the Queensland LNG producers to recover capital costs in Asian LNG spot, or LNG strip, markets would likely result in them being undercut by competing LNG projects (that do not consider sunk capital costs in their forward-looking pricing decisions).

LNG producers and other domestic gas producers will be able to sell uncontracted gas into export markets only if the Queensland LNG plants continue to have unutilised excess LNG capacity (in aggregate).

137 Wood Mackenzie, preliminary report, June 2021, p. 59.

138 Wood Mackenzie, preliminary report, June 2021, p. 54.

Some stakeholders have suggested that the Queensland LNG plants are nearing capacity, and that additional LNG sales would require new capital investment. While some of the LNG projects may approach their nameplate liquefaction capacity at times, the ACCC understands that there remains considerable excess capacity across the three LNG plants (box 6.2).

Box 6.2: Excess capacity of the Queensland LNG plants

The 3 Queensland LNG projects have historically had unutilised, excess LNG liquefaction capacity.

According to AEMO, the 3 facilities have a combined nameplate capacity of 25.3 million tonnes per annum, which is broadly equivalent to about 1,390 PJ.[139] AEMO also note that LNG plants are typically capable of operating between 10-20% above their nameplate capacity — assuming the Queensland LNG plants are also able to operate 10-20% above nameplate capacity, this would mean that total liquefaction capacity of those plants is between about 1,530 PJ and 1,670 PJ per annum.

The ACCC reported in our Gas Inquiry 2017–2025 January 2021 interim report that LNG producers were expected to require 1332 PJ of feedgas in 2021 to meet their long-term LNG SPA volumes, with 105 PJ of this forecast to be used as fuel to produce LNG. The quantity of LNG required to meet the LNG producers' long-term SPAs in 2021 is 1,227 PJ, which is well below the combined nameplate capacity of the LNG plants.

Further, over the course of this inquiry, the ACCC has reported on the quantity of uncontracted gas produced by the LNG producers (in excess of the quantity required to meet their LNG and domestic market contractual commitments). The ACCC's work shows that the quantity of uncontracted gas produced by the LNG producers is typically well below the excess capacity in the LNG plants. Wood Mackenzie suggests the Queensland LNG plants have enough spare capacity to produce 3.5 million tonnes per annum of uncontracted LNG.[140]

In the absence of major new gas discoveries, the Queensland LNG plants are likely to continue to have unutilised liquefaction capacity. This spare capacity means that LNG producers will continue to have an alternative to supplying the domestic market.

This excess capacity suggests that domestic producers will, for the foreseeable future, be able to access LNG export markets as an alternative to domestic supply. This is consistent with expert advice provided by Wood Mackenzie.

It also means sunk capital costs should not be deducted when calculating LNG netback prices.

We welcome stakeholder feedback on our draft decision.

The ACCC seeks feedback on any of the following issues. Where possible, please include supporting information, data and specific examples in your responses.

13. Is the ACCC's draft decision to use its current approach to deducting liquefaction costs to calculate additional longer-term forward LNG netback prices appropriate?
14. What other issues should be considered when estimating and deducting LNG liquefaction costs?

[139] AEMO, Public Report, *Projections of Gas and Electricity Used in LNG*, December 2017, p. 11

[140] Wood Mackenzie, preliminary report, June 2021, p. 52.

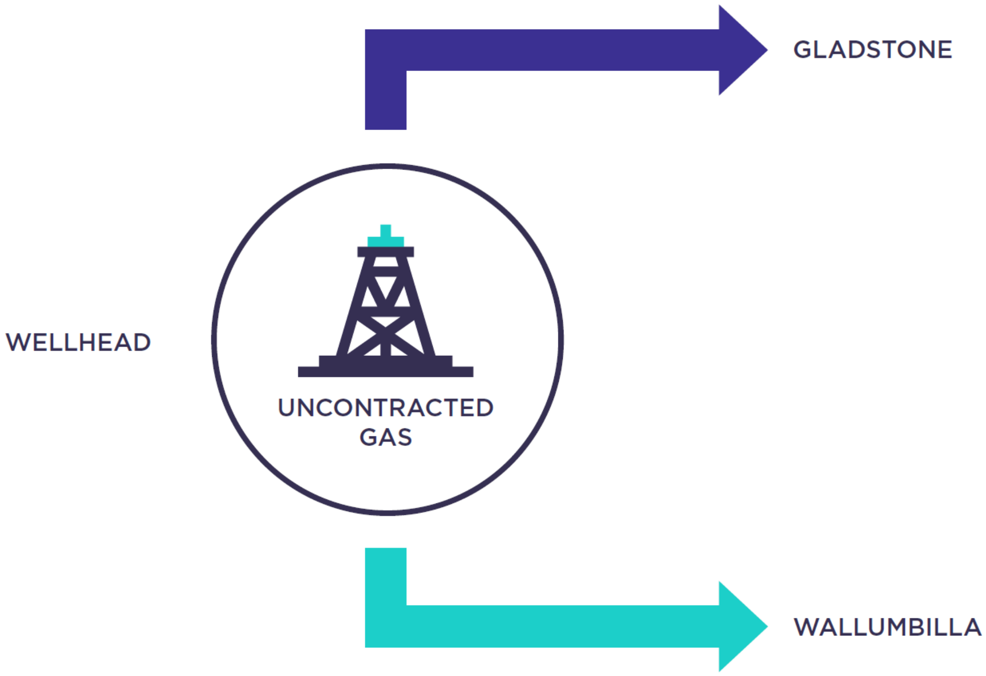
6.4. Pipeline transportation costs

Pipeline transportation costs are the costs of transporting gas from the wellhead to either the LNG facilities in Gladstone or to Wallumbilla.

As shown in figure 6.7, pipeline transportation costs include:

- Pipeline transportation costs from the wellhead to the LNG facility in Gladstone. Suppliers inject export gas into the pipeline system at the wellhead before transporting it to Gladstone. As suppliers can avoid the costs of transporting gas to the LNG facility by supplying the domestic market, we deduct these costs.
- Pipeline transportation costs from the wellhead to Wallumbilla. Since we calculate the LNG netback price series at Wallumbilla, rather than the wellhead, we add the costs of transporting gas to Wallumbilla.

Figure 6.7: Pipeline transportation costs



When we first started publishing the LNG netback price series, evidence from the LNG producers indicated that marginal (or incremental) pipeline transportation costs to transport uncontracted gas from the wellhead to Wallumbilla were negligible.

6.4.1. **Our approach to pipeline transportation costs remains appropriate**

Our draft decision is to maintain our current approach to deducting pipeline transportation costs.

As with the costs of liquefying gas, it is not appropriate to deduct sunk or fixed costs in calculating LNG netback prices, including the sunk costs incurred to build the pipelines or tariffs that are payable under long-term gas transportation agreement.

These costs cannot be avoided by LNG producers and are therefore not considered in deciding whether to supply uncontracted gas to domestic or export markets. Provided there is spare capacity available within these pipelines, sunk and fixed costs do not affect the value of supplying gas to the domestic market relative to export markets.

As such, our current approach to deducting pipeline transportation costs, which only deducts incremental costs, remains appropriate.

This approach is also suitable for a longer-term LNG netback price series. As with liquefaction costs, the incremental costs of transporting uncontracted gas are likely to be similar in the short and long term.

Wood Mackenzie suggests pipelines used by the LNG producers to transport gas to Gladstone have sufficient excess capacity.[141] Consequently, it is not likely that any further investment in these pipelines will be required to export uncontracted gas.

The ACCC seeks feedback on any of the following issues. Where possible, please include supporting information, data and specific examples in your responses.

15. Is the ACCC's draft decision to use its current approach to deducting pipeline transportation costs to calculate additional longer-term forward LNG netback prices appropriate?

16. What other issues should be considered when deducting pipeline transportation costs?

[141] Wood Mackenzie, preliminary report, June 2021, p. 53.

Appendix A: Stakeholder views are now sought on our draft decision

The ACCC seeks stakeholder views on our proposed approach to calculating the LNG netback price series outlined in this draft decision.

Feedback is sought on the following:

The length of the forward LNG netback price series

1. Is the ACCC's draft decision to continue publishing a 2-year forward LNG netback price series appropriate? Should the ACCC continue to publish a 2-year forward LNG netback price series?
2. Is the ACCC's draft decision to publish additional longer-term forward LNG netback prices appropriate? Should the ACCC publish additional longer-term forward LNG netback prices?
3. Over what length of time should the ACCC publish additional longer-term forward LNG netback prices (such as 3 or 5 years)?
4. What other issues should be considered when publishing longer-term forward LNG netback prices.

LNG price markers to calculate the LNG netback price series

5. Is the ACCC's draft decision to continue using JKM to publish historical and short-term forward LNG netback prices appropriate?
6. What is the minimum level of liquidity needed in JKM futures to extend the current forward LNG netback price beyond 2 years?
7. Is the ACCC's draft decision to use prices in medium-term oil-linked LNG contracts to calculate additional longer-term forward LNG netback prices appropriate? Should the ACCC publish additional longer-term forward LNG netback prices based on oil-indexes?
8. Is the ACCC's draft decision to use consultant estimates of an appropriate percentage, or slope, of the oil price to calculate longer-term forward LNG netback prices appropriate?
9. What other issues should be considered in calculating shorter- and longer-term forward LNG netback prices?

Export costs deducted to calculate the LNG netback price series

10. Is the ACCC's draft decision to use the current approach to calculating forward LNG freight costs, for period up to 24 months, appropriate? Should the ACCC use an alternative approach?
11. Is the ACCC's draft decision to use consultant estimates of longer-term forward LNG freight costs appropriate? Alternatively, should the ACCC
    - (g) determine an indicative daily charter rate based on an estimate of the long-run marginal costs (LRMC) of building new LNG freight vessels
    - (h) estimate the extended forward LNG freight cost based on an average of the historical or short-term forward LNG freight costs, and how should the average period be determined
    - (i) estimate the extended forward LNG freight cost as a percentage of the extended forward LNG netback price, and how should that percentage amount be determined?
12. What other issues should be considered in estimating future LNG freight costs?
13. Is the ACCC's draft decision to use its current approach to deducting liquefaction costs to calculate additional longer-term forward LNG netback prices appropriate?
14. What other issues should be considered when estimating and deducting LNG liquefaction costs?

15. Is the ACCC's draft decision to use its current approach to deducting pipeline transportation costs to calculate additional longer-term forward LNG netback prices appropriate?
16. What other issues should be considered when deducting pipeline transportation costs?

Reviewing the LNG netback price series in 2024

17. Is the ACCC's draft decision to undertake another review of the LNG netback price series in 2024 appropriate?