SUBMISSION

GAS INDUSTRY MANDATORY CODE OF CONDUCT | 7 JAN 2023

EUAA
Energy Users Association of Australia

INTRODUCTION

The Energy Users' Association of Australia (EUAA) is the peak body representing Australian commercial and industrial energy users. Our membership covers a broad cross section of the Australian economy including significant retail, manufacturing, building materials and food processing industries. Combined our members employ over 1 million Australians, pay billions in energy bills every year and in many cases are exposed to the fluctuations and challenges of international trade.

As large energy users, our members are highly exposed to movements in both gas and electricity prices and have been under increasing financial stress due to escalating energy costs. These increased costs are either absorbed by the business, making it more difficult to maintain existing levels of employment or passed through to consumers in the form of increases in the prices paid for many everyday items.

Summary

The EUAA strongly supports the Federal Government's proposed mandatory code of conduct (the Code) for the east coast gas industry. ACCC reports have repeatedly shown over the last six years that the east coast gas market has failed to provide a competitive outcome for consumers with producers being able to exercise market power. Our members recent experiences in sourcing gas has reinforced our view that the Code is an essential addition to the suite of Government policies along with the Australian Domestic Gas Security Mechanism (ADGSM), Heads of Agreement and ACCC market monitoring and public reports.

Ideally there would be a more diverse group of competitors in the domestic gas market and there would not be constraints on the development of new fields leading to sufficient supply to support a workably competitive market that does not require the Code. However, these issues are not going to disappear hence neither will the exercise of producer market power. Commentators who criticise the use of a price cap or reasonable price measures seem to have little understanding of how dysfunctional the east coast gas market has become and why such measures are now required.

Nevertheless, Government intervention with a 'reasonable price' has the potential to distort supply and price outcomes if not implemented carefully and that helps neither producer nor consumer. We want producers to develop new fields to provide competitively priced gas to our members and that this does not adversely impact on our international supply obligations. We support the Government's approach with the Code because it will limit the potential for distortion and provide overall net benefits to the economy. Continuation of the current situation is untenable because it will lead to considerable dislocation in manufacturing industries which will have significant flow-on impacts on employment and consumer prices.

The January 2023 ACCC Gas Report[1] highlighted recent producer behaviour in the market with dramatic increases in prices on the back of the war in Ukraine when there was no justification for it apart from rent seeking. As ACCC data shows, price offers for 2023 supply jumped from an average \$9.20/GJ in 2021 to above \$30/GJ in late 2022. We had members being offered 2023 supply at LNG netback prices when LNG netback was above \$60/GJ.

[1] See https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report_1.pdf

These prices had no relation to producers' costs of production. As the ACCC said in its advice to the Federal Government in late 2022[2]:

> "AEMO's 2019 estimates of the lifecycle costs of production faced by gas suppliers on the east coast for 2P reserves (adjusted for inflation) for the costliest sources of supply were below $9.50/GJ, with costs for most supply sources well below that."

Under the Heads of Agreement that LNG producers signed with the Federal Government last September, they were only required to 'offer' uncontracted gas to the domestic market in 2023 'on competitive market terms' which meant they were effectively linked to LNG netback prices[3]:

The most recent ACCC gas report noted that in the period 29th September to 25th November 2022, LNG producers offered over 125PJ of gas to the domestic market for firm supply in 2023 and 2024 but completed contracts for just 2.27PJ. Origin reported last week[4] that it has sold three spot cargoes in the December 2022 quarter. We expect Origin met its' requirement under the HoA, but offering gas to the domestic market at prices that the domestic market cannot afford means the Heads of Agreement has no benefit to domestic consumers and more Government action is required.

These actions by producers were despite clear signals from the previous and current Federal Governments about the impact that the exercise of their market power was having on the Australian economy. As the Treasury Secretary said in evidence to a Senate Committee last November[5]:

> "In summary, the effects of the Ukraine war are leading to a redistribution of income and wealth and disrupting markets. The national interest case for this redistribution is weak, and it is not likely to lead to a more efficient allocation of resources in the longer term…"Policy responses could take many forms but in the current circumstances of generalised price pressures, they need to be mindful of not contributing further to inflation…
>
> This would suggest to us that interventions that directly address the higher domestic thermal coal and gas prices are more likely to be optimal."

It seemed the producers considered that their social licence obligations to Australian consumers ended with their commitments under the Heads of Agreement.

The recently well quoted old saying "the solution to higher prices is higher prices" only works in a properly functioning competitive gas market and does not apply to the east coast where LNG exporters and their associates have influence over 90% of 2P east coast reserves.

We are strong advocates for additional supply as a means of putting downward pressure on prices, but it is a rather simplistic solution to a complex problem. Long term State restrictions on exploration and development of new

[2] See https://treasury.gov.au/sites/default/files/2022-12/c2022-343998-accc-advice-summary.pdf
[3] See p.1 https://www.industry.gov.au/sites/default/files/2022-09/heads_of_agreement_the_australian_east_coast_domestic_gas_supply_commitment.pdf
[4] See https://www.originenergy.com.au/about/investors-media/quarterly-report-december-2022/
[5] Quoted in https://www.afr.com/politics/federal/treasury-gives-green-light-for-gas-price-intervention-20221108-p5bwdp

fields will not change in the future. Santos continues to face hurdles in developing the Narrabri project that is dedicated to local supply at the same time as reserves in Victoria are depleting[6].

The impact of these policies is seen not only in the debate around gas prices and availability for C&I customers. It is also seen in the recently announced increases of up to 36% in retail gas prices for residential and small business consumers in eastern states. Gas prices affect all parts of the economy.

The Queensland Government's domestic acreage reservation policy for manufacturing industry is a good start to addressing domestic supply concerns. However, the absence of a requirement for reasonable pricing allows sellers to pursue prices just below the price offered by LNG producers who have LNG netback as their opportunity cost. Introducing the Code, with reasonable pricing provisions, offers a timely intervention to ensure that all producers in the east coast market participate reasonably and fairly with domestic gas users.

Following a direction from the previous Federal Government, we spent over 12 months in negotiation with the producers on a voluntary code. Regrettably, despite repeated efforts to introduce meaningful provisions, we concluded that a voluntary code would have no beneficial impact on the situation given it had no effective sanctions and no reference to price. Frustrated by this lack of meaningful progress we withdrew from the final stages of its development.

We agree with the ACCC's comments on the voluntary code in their advice last December to Government – the EOI provisions did not meet the need of buyers, it was not capable of enforcement or dispute resolution and it contained ambiguous pricing positions.[7] We recognise the potential efficiency benefit of using the voluntary code in developing the Code but it has limited use. The voluntary code was effectively designed for producers, by producers, and the Code must provide a more balanced, purchaser-led structure to have meaningful impact.

We support the fast track process to finalise the Code because we want producers and our members to have the regulatory certainty to quickly resume negotiations for gas supply in 2024 and beyond. Our main concern about the fast track process is that it means it is not possible to fully consider the inclusion of other market players, including retailers and any future LNG terminal owner/operator. Many of our members contract with retailers who have been offering $30/GJ + contracts in recent months. This submission proposes several measures for the ACCC to give retail C&I customers comfort that retailers are not continuing to exercise their market power. If ACCC market monitoring provides evidence of this then retailers should be quickly brought into the Code.

Since the release of the Consultation Paper we have observed many dire predictions for the future of east coast gas supply which seem similar to predictions made when the Western Australian Government introduced their 15% gas reservation policy in 2006. Since then, WA gas consumers have had the benefits of competitive prices at the same time as there has been a massive expansion in the LNG industry.

On the east coast, the producer argument is centred around the incentives to invest in new supply. They are concerned that the $12/GJ price cap will be a marker for the reasonable price in the Code and that this price is not sufficient to support their future investment in new field development. This is difficult to believe when producers

[6] See discussion in Chapter 6 https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report_1.pdf
[7] See https://treasury.gov.au/sites/default/files/2022-12/c2022-343998-accc-advice-summary.pdf

were very happy with an average of $9.20GJ in 2021 for supply in 2023 and beyond. It will be interesting to see what data is presented to the ACCC on how costs have changed since 2021.

The producer argument against the inclusion of reasonable price provisions in the Code seems to be that it will:

- remove the incentive to invest in new reserves to supply the domestic market,
- which will lead the Federal Government to trigger the ADGSM and force LNG producers to divert volume away from long term LNG Sales and Purchase Agreements to supply the domestic market to the detriment of our international trading partners.

For this logic to work it would require LNG producers, which are earning very large profits from high international prices, consciously not developing new fields to supply their SPAs and run the risk that it is the Government, not the producers, who will suffer the reputational damage. We agree with the reported comments of the ACCC Chair saying that the significant revenue LNG producers are currently receiving from a large majority of their total sales is available to fund exploration and development of new fields to supply the domestic market[8].

A final point to note is that gas pipelines under Part 23 of the Rules effectively operate under a mandatory code without it being called a mandatory code – information disclosure requirements, obligation to negotiate in good faith and dispute resolution process that could be a model for this Code all designed to get an outcome that would occur in a workable competitive market. Our view is that this has made a significant contribution to the efficient operation of pipelines.

While the ACCC cannot force gas producers to contract new supply, we hope that they will respond in a positive way to the Code that enhances their social licence and provides for both a thriving domestic manufacturing and gas industry.

In summary, in this submission we:

- Support the development of the code on a fast track to ensure it is in place as soon as possible to given producers confidence on the rules that will apply and allow our members to start contracting for 2024 and beyond by mid-2023,
- Support the Governments overall approach – facilitate commercial negotiations with the purchaser having greater bargaining power given the threat of binding arbitration based on a 'reasonable price' measure,
- Propose extensive ACCC monitoring of retailer market behaviour to assess whether they should be brought into the Code,
- Propose a 'best endeavours' obligation on producers to publish on a quarterly basis, the intended contract (through EOIs) and spot volumes to be offered to the market and the timetable in each EOI for reaching an agreed GSA,
- Provide a list of prescribed minimum details to be in the EOI,
- Argue that an LNG import terminal is considered a producer and covered by the Code,
- Provide high level comments on how the reasonable price might be determined,
- Support an efficient low-cost disputes framework drawing on that used in Part 23 of the NGR for gas pipelines,

[8] See https://www.theaustralian.com.au/nation/politics/gas-super-profits-fund-exploration-says-gina-cassgottlieb/news-story/748d0a401b22d1d6279391020a90439e

- Emphasise the need for the ACCC to closely monitor the spot market to ensure producers do not seek to avoid the Code by not entering into GSA's and increasing sales into spot markets,
- Ask the ACCC to consider how it might make more timely data on market performance publicly available,
- Recommend the first Code review to be completed within 12 months of the date of commencement of the Code and that the Code stay in place until the ACCC decide that the gas market can meet the requirements of a 'workably competitive market'.

Purpose

We agree with the purposes outlined in the Consultation Paper (p.9):

- Address bargaining power imbalances between producers and buyers in the domestic wholesale gas market.
- Set minimum standards for dealings between producers and buyers, ensuring a clear and certain commercial negotiation framework.
- Support producers and buyers to arrive at agreements on reasonable terms and,
- Provide a reasonable pricing provision to ensure that domestic prices are set at reasonable levels given the underlying costs.

and would add the following:

- Setting requirements on producers to make gas available for term contracts.

This is to avoid producers selling on spot markets to avoid the Code.

Obligation on producers and purchasers to act in good faith

We support the current approach in mandatory codes of relying on the common law to determine whether a party (seller or buyer) has acted in good faith rather than providing an inflexible definition. While there are good faith provisions in the voluntary code, we would submit that the good faith provisions in the Code should be consistent with that in other mandatory codes rather than simply copying what is in the voluntary code.

Requirement for gas producers to publish and otherwise make offers broadly available to the domestic market

A major concern of our members in recent years is how producers have sought to exercise their market power through the timing and breadth of availability of EOIs they put into the market. Often our members have attempted to directly negotiate with a supplier, or run their own EOI process, only to be told by a producer that they do not intend to respond to the buyer EOI and the member is required to respond to a producers EOI. Our members had no idea of when producer EOIs would be issued – they only knew about them when they turn up in their email in-box.

This approach is biased to the producer. Knowledge of available gas and a suitable price point is already asymmetrical and this eliminates competitive tension in the negotiating process because a purchaser no longer has a next best alternative. Gas users must follow strict internal approval and governance processes and it is difficult, if not impossible, to quickly mobilise internal stakeholders and Boards on short notice with little information to share as to the relative merits of the proposed arrangement.

The Code should provide for a 'best endeavours' obligation on producers to publish, each quarter, a timetable of proposed EOIs for the following 12 month period setting out:

- the intended volume to be offered in each contract year
    - through an EOI process covered by the Code, and
    - to the spot market
- the proposed timetable for negotiations from issuing the EOI to finalising the GSA.

This will be very helpful to buyers to manage their re-contracting strategy. We understand that information can change as producers complete their due diligence prior to actually issuing an EOI e.g. amending volumes based on revised reserve estimates. Nevertheless, reasonable efforts should be made to supply information and to update it when information becomes available. It is important that producers turn their minds to contracted vs uncontracted volumes, which alerts the market to the certainty of supply and to the potential for gas to makes its way to the spot market.

Many of our members are sophisticated users on the wholesale market, yet there are many members who are required to purchase from retailers because the minimum volume required from producers is 0.5PJ pa. In the absence of retailers being covered by the Code, we believe that a producer EOI should be advertised as being available to any buyer with an annual consumption of ≥0.1PJ.

Requirements for gas producers to disclose certain information in EOIs and their timetable for making offers and reaching agreement

As a general principle we support more rather than less prescription. Producers should be required to provide:
- an indicative timetable for negotiations that provides flexibility for both parties
- a statement that the offer will not be withdrawn at any stage of the EOI timetable described above unless there are extraordinary circumstances
- information on the quantity of gas available, the term, delivery point(s) and maximum daily quantity
- the P2 reserves the contract will be supplied from and whether they come from an existing or newly developed field
- the proposed starting price and escalation method and the non-price terms that this price path is based on e.g. take or pay, load factor, trading and banking flexibility
- how the starting price would vary with changes in those non-price factors
- if the proposed price is delivered then the transport component to the purchaser's flange showing the individual pipeline tariffs that make up the total transport cost
- standard clauses e.g. dispute resolution, default and force majeure provisions and
- any producer conditions precedent to entering into as gas supply agreement e.g. final investment decisions on developing a new acreage or project to source gas under any GSA

There will also need to be a clear process for how potential buyers can register to participate in the EOI to ensure the volume under negotiation is no greater than the volume available. We wish to avoid the situation where negotiations end up in arbitrator decisions for a combined gas volume greater than the producer made available in the EOI.

Make clear that buyers EOIs are also covered by the Code

Our members want the option of sending out their own EOIs that a producer will respond to. We understand the Government's intention is to include buyer EOIs in the Code. This should be explicitly mentioned in the Code. Failure to respond to a buyer EOI should be a breach of good faith.

Dispute resolution

This applies up to the point a full form GSA is signed after which the dispute resolution clauses in the GSA would apply.

We support a 'graduated' approach to dispute resolution where arbitration is a last resort and use of anti-avoidance provisions a back stop to the last resort. We want to see transparent commercial negotiations along the lines of what would occur in a workably competitive market. This graduated approach could be:

(i) initial discussions directly between the parties
(ii) if there is written evidence that this has been tried but a dispute remains, then go to formal mediation
(iii) if mediation fails then the last step is binding arbitration
(iv) there is still the right to go to court on matters of law.

Disputes can be raised at any stage of the EOI process up to the signing of the GSA e.g. if a potential purchaser believes the EOI does not satisfy the Code information requirements. Arbitration on matters related to good faith and other aspects of the Code must remain open to purchasers even where they choose to enter into an arrangement outside the reasonable price provisions e.g. if they wish to have an oil linked price. This ensures a consistent approach by producers in the market and levels the playing field.

We think that the disputes provisions of Part 23 Division 4 of the National Gas Rules[9] offer a model worth considering for final resolution in a cost-effective and efficient manner. These provisions provide an established and tested framework for arbitration on matters relating to good faith and pricing, which should lead to a more efficient way of bringing this Code online. Importantly, adopting similar dispute provisions in the Code addresses bargaining power imbalance, limiting the expenditure of significant resources that may act as a deterrent to purchasers exercising their rights.

The Code should include arbitration that adopts an 'on the papers' process, namely that the parties avoid face-to-face proceedings in favour of written submissions. We support the adoption of other provisions in the National Gas Rules in relation to costs, the appointment of experts and procedures, with the necessary amendments to suit the Code. The decision should be binding on the producer but not on the buyer to reflect the residual market power imbalance even with a Code.

We support limited public disclosure of information following the conclusion of an arbitration – the identity of the producer with a summary of the matters the arbitrator decided would be sufficient. There should be no disclosure of the specific GSA terms. Regular ACCC gas reports would present anonymised data.

[9] See https://www.aer.gov.au/networks-pipelines/non-scheme-pipelines/arbitration-of-access-disputes

Standard provisions on compliance and enforcement

We support the inclusion of compliance, enforcement and penalty provisions aligned with other mandatory codes including:

- Provision of documents to the ACCC
- Ability of a buyer to make a confidential submission to the ACCC on alleged breach of the Code
- Maximum pecuniary penalties for breaches of civil penalty provisions expressed in penalty units

We would also support the imposition of higher pecuniary penalties for particular contraventions as is the case under the Franchising Code.

Specific measures need to be included to protect retail gas customers

We understand that the Government's desire, which we strongly support, to have the Code operational as soon as possible, means that gas sales by a retailer are not explicitly included in the first Code. This applies to a wide variety of retailers e.g. a standalone retailer, a retail arm of a vertically integrated gas producer or a related entity of a producer.

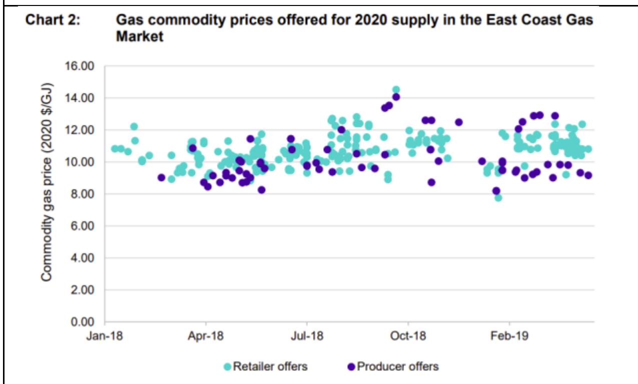
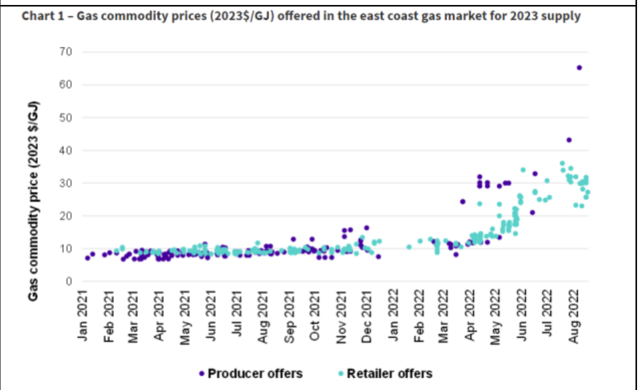
However, 'retail' is a lot more than residential and small business. There are many C&I customers that are a crucial part of the Australian economy that also need to be protected from the exercise of market power. These smaller C&I customers do not have gas comparison websites to compare offers and switch retailers. They are not covered by the AER and Essential Services Commission market monitoring. They are not subject to the National Energy Customer Framework in the ACT, Tasmania, SA, NSW and Queensland or the Energy Retail Code of Practice in Victoria.

They employ many thousands of Australians and supply a whole range of goods to consumers. They generally operate on small margins. Even if gas is only 5% of their costs, a tripling of gas costs can wipe out their total margin unless the buyers of their products agree to a cost pass through. Our members in this situation are saying gas cost pass through in the prices they charge for their products is often very difficult to achieve but in the end it means higher consumer prices.

Many of our members purchase their gas from retailers for a range of reasons:

- Producers refuse to offer gas to customers with 'lower' annual volumes, including sophisticated members with wholesale gas arrangements in other States,
- Retailers offer a 'complete' delivered price contract so the member does not have the complications of having to arrange transport, manage deviations on their spot gas purchases or need to manage prudential exposure through pre-payments or bank guarantees,
- The retailer may have pipeline capacity that is not available to the buyer and
- Producers may have gas but there is no pipeline capacity to haul it on a firm basis for the volumes required.

Until 2022 buying from a retailer was a reasonable decision for a member to take. As the ACCC Gas Report data indicates, retail offers were not much different to producer offers. The data in the ACCC's January 2023 report only covers offers up to August 2022 – our members experience is that the significant rise in prices continued to the end of the year until the gas cap legislation came into effect and, regrettably, offers stopped.

ACCC Interim Report – July 2019 p.21	ACCC Interim Report – January 2023
	

With the start of the gas cap period where retailers are not covered, our members experience of retailers is a combination of:

- Limiting offers to existing customers and declining to make an offer to a new customer whose only option is the spot market,
- Offers above $30/GJ commodity – seemingly irrespective of whether the retailer has a wholesale supply or is simply providing a short-term fixed price contract and buying off the spot market to supply,
- Existing customers going to very high fixed tariffs or default tariffs at the price cap of $40/GJ at the end of their existing contract because of a lack of uncontracted gas supply under their wholesale contracts,
- Some C&I customers have been forced onto spot price contracts with Retailers who refused to offer fixed priced contracts; these customers were left with a choice of remaining on default pricing or accepting spot price which they have no ability to manage,
- Lack of transparency regarding where the supply for the contract will be sourced, and declining to provide this information when requested, and
- Our members have no way of knowing if the retailer's representations on no uncontracted gas supply are correct.

Given these concerns we would propose the following measures in the Code to protect retail customers:

- Producers are required to engage with buyers of at least 0.1PJ/year per market delivery point which respond to their EOIs with the buyer acknowledging that they are on a wholesale contract; we wish to avoid the situation where:
    - producers do not allow members to participate in producer EOIs
    - members issue an EOI to retailers and they refuse to respond
- The ACCC closely monitors retail offers to:
    - Ensure producers are not moving sales from the producer part of the business to the retail part of the business to avoid the Code e.g. retail sales by a producer which is vertically integrated, retail sales by a related entity of a gas producer and retail sales by an entity which is in a joint venture with a gas producer or affiliate of a gas producer,
    - Ensure that any sales between vertically integrated businesses are at arms' length having regard to the price otherwise offered by the producer entity and accepted by the retailer entity,

- Ensure they are reflecting the aggregate of costs in their wholesale gas agreement with producers in the prices they offer buyers i.e. passing through the benefit of gas at lower prices including from legacy arrangements, rather than pricing to the marginal molecule,
- Ensure they are reflecting actual transport costs in the delivered prices they are offering buyers i.e. the transport costs they incur (or don't incur in the case of swaps) and not the tariff price if they do not have exposure to it
- Gather data on the retail margin buyers are being charged to assist in future if retailers are brought into the Code

and the publishing these results as part of the regular Gas Inquiry Interim Reports.

As a natural complement to the ACCC monitoring of retailer behaviour in case a future version of the Code would include retailers, we recommend that the ACCC be prepared for that eventuality by:

- Understanding the legal issues that would need to be addressed to bring retailers under the Code for customer with annual demand ≥0.1PJ e.g. National Retail Law and the need for enabling State legislation
- Undertaking preliminary data collection to enable the future quick calculation on the retail margin for gas retailers; this should, if required, involve undertaking a consultation process on how retailer costs and allowances should be calculated prior to any decision to include retailers in the code[10].

The ACCC's role would cover all categories of retailers listed above.

Application of the Code to LNG import terminals

There is no mention of this category of gas seller in the Consultation Paper. Given such terminals are not a 'domestic gas producer' it may be arguable that the Code does not apply to them. LNG import terminals may not be retailers either, meaning a prospective customer has neither the protection of the Code nor the benefit of a retail contract.

We support a more expansive view of 'producer' to include a supplier of gas that offers gas in the east coast market other than as a retailer. If a current producer introduces an LNG import terminal, that gas must be considered as from the producer. If supplied as a retailer, it should be captured accordingly. It may turn on the final structure of LNG terminals. What is important is that there is no gap left open before an LNG import terminal is a real option.

There may be additional aspects to consider in more detail and we encourage further thinking on this issue.
It remains to be seen whether there is a business case for LNG terminals once the Code is in place[11]. We would propose that were an LNG terminal be built then it should be classed as a producer, not a retailer and hence covered by the Code.

[10] Similar to the current AER review of retailer costs and allowances under the Default Market Offer; see https://www.aer.gov.au/system/files/AER%20-%20Default%20market%20offer%20-%20Price%20determination%202023-24%20issues%20paper%20-%203%20November%202022_0.pdf

[11] The developers of the proposed Newcastle import terminal announced last week that it will no longer proceed.

How should reasonable price (RP) be defined?

We understand the approach will be:

- The methodology based on a cost build-up is to explicitly delink domestic prices from international prices; in doing so we recognise that if at some time in the future the LNG netback price falls below the RP, the RP will not be amended,
- the ACCC will set (a) 'vanilla' reasonable price(s) at the beginning of the Code's operation; the ACCC has yet to decide whether there is more than one reasonable price and whether it will be accompanied by a range of benchmark non-price terms,
- This will act as a reference price in negotiations – a guide, not a requirement or cap or floor,
- If negotiations and then mediation fails to get agreement then the buyer can go to arbitration; the arbiter will be able to draw on the RP as a 'guardrail' and compare that to the specific contract details that are the subject of the arbitration.

We do not underestimate the complexity of the ACCC's task. We start with the following principals:

- It is based on the efficient long run marginal costs of domestic supply, and
- It is used in a way that encourages commercial agreement prior to the need for arbitration.

The ACCC in its advice to Government is that the RP (p.3):

> "… would be assessed with reference to the cost of the most likely new domestic gas production to meet forecast domestic demand…"

with a building block approach based on opex, depreciation, return on capex and allowance for tax and royalties. Some thoughts for consideration:

How should existing developed fields be treated?

An EUAA member seeking a contract for supply in 2024 and 2025 is most likely to have that gas sourced from an existing developed field, not a new field. This existing field might have been developed some time ago and have been supplying buyers for many years so significant depreciation charges may have already been made against that asset. We consider it reasonable that the price our member pays reflects the age and production costs of that field. That is the case in a workably competitive market that the Code is designed to try to replicate.

The uncontracted gas LNG producers will make available under the Code will be sourced from a whole range of fields developed primarily to meet LNG commitments. This suggests that the RP calculation should initially reflect the fact that supply will come from existing fields. Over time this would be a 'rolling' calculation that gradually increases the 'weight' of new fields in the calculation.

But which new field?

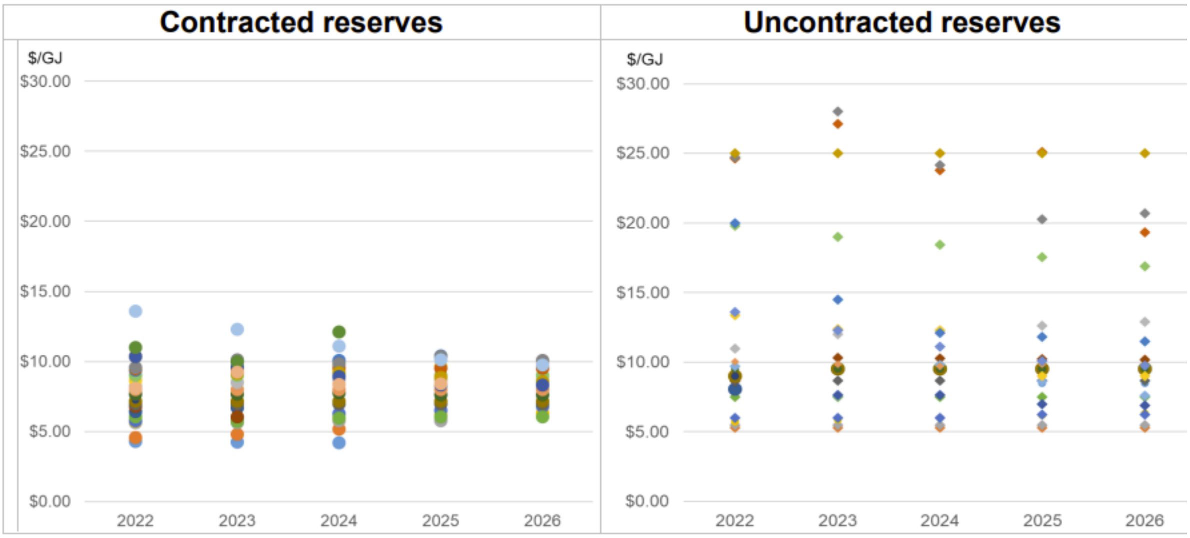
We would expect the most likely new field would be the one with the lowest expected costs. In the past when our members have sought to get supply from the low cost CSM fields in Queensland (based on company's ASX reports of production costs), the producer response has been 'no these low cost fields are reserved for LNG because that is where we make our best return on investment given fluctuating LNG prices. Given domestic customers generally pay a fixed (base + escalator) price, their supply comes from higher cost fields.

The RP calculation should be based on the next lowest cost field, irrespective of where the intended buyer is located

We think the data the ACCC provides on price assumptions underpinning producer reserves is very relevant

The January 2023 ACCC gas report provided this data on the price assumptions for producer calculation of uncontracted reserves.

Chart O.5: Price assumptions underpinning reserve estimates (real $2022)



Source: ACCC analysis of data obtained from producers.

As the ACCC noted (p. 19):

> "This shows that the majority of currently contracted and uncontracted reserves are commercial at $10/GJ. However, there are a number of currently uncontracted reserves that are commercial at higher prices. Further work is required to understand how these higher price estimates relate to the cost of production."

ACCC should provide guidance on how the RP might be applied by an arbitrator

This would be modelled on the guidance note the ACCC recently released on the application of the $12/GJ cap. A draft of the proposed methodology and guidance on application should be released for comments with the Draft Code.

The ACCC should review the RP regularly but not too frequently

This would ensure both producers and buyers have confidence in the RP reflect changes in underlying variables e.g. changes in royalty rates or inflation. However too frequent reviews may provide an incentive to producers to not offer longer term contracts if they think a future RP will be higher.

We are keen to engage with the ACCC as it develops the detailed methodology.

The ACCC should closely monitor spot markets

We can understand the Government's decision to exclude spot markets from the code to give some flexibility to the overall market.

Historically east coast buyers have sourced their gas under term contracts. The spot market has been used as an 'overs and unders' type of market where market participants can trade their excess gas – whether it be a producer with some increased production or a buyer that is having a facility shut down for maintenance. Volumes traded are a relatively small proportion of total gas sales. By contrast Henry Hub in the US is a very deep market with lots of suppliers, lots of interconnected pipelines and a history that gives buyer and sellers the opportunity to eschew term contracts and rely on the spot market for at least a reasonable proportion of their requirements.

We are concerned about the risk of producers moving volume out of the contract market bound by the Code and into the spot market that will not operate on a 'reasonable price' provision. The ACCC will need to monitor closely how the spot market develops when the Code is implemented to give consumers confidence that producers are not using the spot market to avoid the Code.

The ACCC should seek ways to produce its market information in a timelier way

The regular ACCC Interim Reports published each February and August provide very comprehensive data collected from sellers and buyers that finishes around 5-6 months before the publication of the report. Having raised this issue with the ACCC we understand that its information gathering powers under the Act have prescribed times for the provision of that information and then there is the time required to analyse and put it into publication format. This is what drives the 5-6 month lag.

We appreciated the early publication last December of price offer data that was in the January 2023 report and the data on LNG producer offers vs firm contracts in late 2022 cited above. We would encourage the ACCC to continue and expand this practice as much as possible. We hear real time information from our members of what is happening in the market e.g. the surge in price offer in the December quarter 2022 and yet this will not become public until the August 2023 Interim Report – unless the ACCC again publishes some data early.

We have found that often the claims made by producers on current market activity is contrary to what our members are experiencing but we then have to wait 6 months before the ACCC Interim Report is published to substantiate our experience.

Given the ACCC's role in administering the Code and in providing oversight of retailer activities discussed above, we would encourage the ACCC to seek ways of making more timely information disclosure of what they are seeing is happening in the market. We do not want a situation when we see retailers exercising their market power and it taking 12 months to include them in the code.

Code Term

The Code should remain in place until the ACCC concludes that the gas market meets the definition of a 'workably competitive market' as defined in the AER Non-scheme Pipeline Arbitration Guide[12] which quotes the definition in the Independent Committee of Inquiry on National Competition Policy (the Hilmer Committee) in 1993:

> "In markets characterised by workable competition, charging prices above the level of long run average costs will not be possible over a sustained period, for higher returns will attract new market entrants or lead customers to choose a rival supplier or product…
> Where the conditions for workable competition are absent — such as where a firm has a legislated or natural monopoly, or the market is otherwise poorly contestable — firms may be able to charge prices above the efficient level for periods beyond those justified by past investments and risks taken or beyond a time when a competitive response might reasonably be expected. Such "monopoly pricing" is seen as detrimental to consumers and to the community as a whole."

We do not support a specific sunset clause for the code – other mandatory codes do not have a termination date. There should be regular reviews of the Code's effectiveness and we support the first review being completed within 12 months of the Code becoming law. This first review should specifically consider the ACCC's evidence of its market monitoring activities particularly on retailers and the spot market. The rules governing the conduct, scope and publication (with a requirement that it be public) of these reviews should reflect the rules in other mandatory codes.

The Code should remain in place as long as the ACCC judges that producers are able to exercise market power. It would end when the ACCC judges that the market is 'workably competitive'.

Thank you for the opportunity to make a submission. We would be happy to discuss these issues further if required.

Kind regards,

Andrew Richards
Chief Executive Officer
7 February 2023

[12] See the discussion at pp 3-4 in https://www.aer.gov.au/system/files/AER%20Non-scheme%20Pipeline%20Arbitration%20Guide%20-%20September%202017.pdf