



## **PUBLIC SUBMISSION TO THE EAST COAST GAS INQUIRY – ISSUES PAPER**

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### **INTRODUCTION**

QGC welcomes the opportunity to respond to the East Coast Gas Inquiry Issues Paper (the Paper) released on 4 June 2015. QGC is a leading natural gas explorer and producer focused on supplying gas to domestic and international markets.

We are the developer and operator of the US\$20.4 billion Queensland Curtis LNG (QCLNG) project, the world's first to liquefy natural gas from coal seams. The QCLNG project involves gas production in the Surat Basin, transportation through a 540 kilometre pipeline network, and production and export of liquefied natural gas (LNG) from Curtis Island at Gladstone. The sale of this pipeline to APA Group was recently completed and it is now referred to as the Wallumbilla to Gladstone Pipeline.

QGC is also a supplier of natural gas to Queensland, providing – on average – 20% of Queensland's natural gas demand since 2006. Even with the commencement of QCLNG exports, meeting our long-term domestic supply commitments remains our priority for production.

QGC is the Australian asset of BG Group plc, a London Stock Exchange-listed company and a world leader in natural gas with considerable experience in operating and trading in mature international gas markets. It is with this experience, as a gas producer and active participant in both domestic and international markets, that we provide the following information to the Australian Competition and Consumer Commission's (ACCC) East Coast Gas Inquiry.

As a member of the Australian Petroleum Production and Exploration Association (APPEA), we also support its response to the Paper.

### **SUMMARY**

While this submission directly addresses questions in the Paper (where these relate to our business operations and experience), our key conclusions can be summarised as follows:

#### **1. The emergence of the East Coast LNG industry is a once-in-a-generation economic opportunity for Australia**

The QCLNG project is one of Australia's largest capital projects, involving investment of US\$20.4 billion. It employed approximately 14,500 workers at peak construction (November 2013) and, in steady state operations, will maintain a workforce of about 3,400.

It is one of three LNG projects being developed in Eastern Australia – a combined A\$60 billion investment that will see LNG become Queensland's second largest export industry. This unprecedented investment will be a long-term source of employment and export income for Australia.

## **2. The East Coast Gas Market is a market in transition**

The East Coast gas market is transitioning from a small domestic market, underpinned by long-term contracts between suppliers and domestic users, to one linked to international markets via the LNG projects. This linkage to international markets and prices has enabled the recovery of gas from previously uneconomic sources and facilitated the development of a globally significant gas industry in Queensland that supports both the domestic and LNG markets.

The LNG projects are highly capital intensive and represent the world's first in terms of developing CSG to LNG. They face unique and changing production and commercial risks throughout their development life-cycles. Project proponents have responded to these changing risks during the different stages of the development cycle and the nature of their involvement in the market has necessarily varied over time.

The evolution of how Operators such as QGC and the other LNG proponents have engaged with the East Coast Gas Market over the project development cycle is a feature of a market in transition, rather than a market lacking competition.

## **3. As LNG projects become operational, market design changes will be needed to ensure gas flows to centres of highest demand**

With QCLNG now operational, we believe elements of the domestic market could be significantly improved to facilitate the effective allocation of gas, particularly during LNG production swings when significant volumes of gas become available at short notice.

While QGC continues to support COAG's gas market reform agenda, there is a role for Government to advance development of issues such as access to pipeline capacity, hub development and transformation of market information. There are also key learnings from international gas markets on how to address these emerging challenges

## **4. Improved market function including, the removal of regulatory barriers, will help unlock further gas development for domestic and international markets**

QGC believes a well-functioning gas market is the most efficient and cost-effective means of generating the investment signals needed for new gas development. To this end, QGC has been a supporter of COAG's gas market reform agenda and an active participant in the recently established Wallumbilla Gas Supply Hub.

QGC also supports the removal of unnecessary development moratoria and regulatory restrictions in some parts of Eastern Australia – particularly in Victoria and NSW.

## **5. Interventionist policies – such as reservation – are a disincentive to gas development**

Interventionist-type policies, such as domestic gas reservation, distort price signals and deter investment, resulting in reduced supply in the longer-term. QGC supports the findings of the Australian Government's Energy White Paper, which argued that reserving gas production for the domestic market would have negative consequences for the economy and that encouraging a diversity of suppliers and additional supply was a more appropriate response to questions of price and availability.

## RESPONSE TO QUESTIONS

### CHANGES AFFECTING THE DOMESTIC GAS INDUSTRY

*Q1. How are changes in the gas industry affecting gas buyers? Provide details of the key changes and explain their effects, including whether the effects vary by location and whether these effects are expected to be temporary in nature.*

The exponential growth of the Coal Seam Gas (CSG) industry, together with the establishment of a world scale LNG industry in Queensland, is transforming the gas sector. It is transitioning from a small domestic sector, underpinned by long-term contracts between suppliers and domestic users, to one linked to international markets via the LNG projects.

This linkage to international markets and prices has enabled the recovery of gas from previously uneconomic sources and facilitated the development of a globally significant gas industry in Queensland that supports both the domestic and export markets. The development of the LNG projects has also delivered material benefits in terms of economic growth, the development infrastructure and encouraging the establishment of more sophisticated market mechanisms for managing risk.

Given the LNG projects are the world's first to be supplied by CSG, they have faced unique and changing production and commercial risks throughout their development. These projects are more complex than conventional LNG projects. CSG fields carry a greater degree of uncertainty into the development phase. This is driven by the complexity of the upstream fields as reserves and deliverability are less defined at the commencement of development than in conventional gas developments – indeed in an unconventional context, ongoing appraisal and development are often conducted in parallel. Hence, the uncertainty is at its greatest during the initial ramp phase of production.

The changing nature of this subsurface uncertainty (including the rate of dewatering) as projects move through the development cycle is reflected in the nature of engagement with the market:

- In the initial (pre-LNG) stages of development of the CSG industry in Queensland, “foundation” domestic Gas Supply Agreements (GSAs) underpinned investment and played an important role in “firming up” the resource for the purposes of reserves certification. Typically these foundation GSAs were entered into with gas retailers, power stations and local manufacturers.
- Following LNG project sanction, as the projects moved into the capital intensive construction phase, the proponents’ focus was ensuring the timely development of reserves to underpin the supply commitments associated with the new facilities whilst continuing to fully honour their domestic commitments under the foundation GSAs. A key uncertainty for the projects to manage during this phase was the ramp profile (linked to de-watering) necessary to supply feedgas to the LNG plants following construction. Accordingly, during this period, QGC was not in a position to commit to additional long-term firm domestic gas supplies.
- As the QCLNG Project has approached (and indeed commenced) commissioning and start-up, QGC has increasingly used innovative short-term products to manage the sale of ramp gas and to operationally balance supply and demand within the QCLNG system in response to short-term events.

These responses are features of a market in transition, rather than a market lacking competition. Furthermore, this change is not unexpected given the relative scale and complexity of the projects relative to the characteristics of the domestic market.

In addition, QGC has entered into a number of other commercial agreements that facilitated investment by third parties in infrastructure and that will assist in managing our on-going short and long positions. These arrangements includes physical pipeline inter-connections, storage agreements as well as a number of Master Spot Agreements (MSA) with third parties (producers, LNG projects, retailers, large industrial and power generators) which enable the ability to buy, sell or swap gas under subsequent transactions at short notice.

The MSAs have been developed in the absence of a standard industry form agreement within the Eastern Australian gas market. More liquid traded markets (such as the electricity market in Australia) make extensive use of standard form agreements to facilitate short-term trades e.g. ISDA agreements. Once executed, these agreements reduce future transaction costs and facilitate increased trade between players in the market.

Infrastructure projects that have been underpinned by commercial arrangements put in place by QGC include:

- Development of the Condamine Power Station
- Mt Larcom interconnect (GLNG)
- Wandoan interconnect (APLNG)
- Underpinned Silver Springs storage project (AGL)
- Interconnection with Arrow Energy
- Converted Berwyndale-Wallumbilla pipeline to bi-lateral flow

The development of the LNG industry also led the Australian Energy Market Operator (AEMO) (on the request of Governments) to establish the Wallumbilla Gas Supply Hub (GSH). QGC has been an active participant in the development of the GSH, which enables the sale and purchase of short-term gas on a “balance-of-day”, “day-ahead” and weekly basis. While still in its early stages of development, the GSH provides an additional point of trade and a level of price transparency that previously did not exist. To date, its most active period of trading was during the third quarter of 2014 during QGC’s “ramp” phase prior to the commissioning of our first train.

Moving forward, the uncertainty in production and offtake through the LNG “ramp” phase will dissipate as the projects move into “steady state” production. During this stage of “steady state” operation, the requirement to manage the short and long positions of the LNG plants will see the need for greater flexibility to manage short term production volatility. This will drive greater participation in short-term markets through the development of innovatively structured bi-lateral transactions and exchange traded products.

There is also considerable uncertainty as to what the domestic requirement for gas is going to be over the longer term.

- There has been a progressive reduction in the forecast requirements for natural gas from AEMO in each update of the Gas Statement of Opportunities (GSOO) and in the 2014 inaugural Gas Supply Forecast Report.
- The domestic requirement for gas over the term of the LNG projects based on AEMO projections has reduced from c12tcf to less than 9tcf in recent years.
- This has been driven primarily by a decline the requirement for end use electricity demand. This has reduced the requirement for gas for base load power generation in Eastern Australia due to an existing oversupply of coal based generation.

The decline in electricity demand has seen some gas re-contracted for supply to the LNG projects under flexible terms which allow for the intermediary to re-call gas for the domestic market when required.

*Q2. Are gas suppliers in Eastern Australia likely to meet both LNG export commitments and domestic gas demand over the life of the projects, given the gas reserves base and the expected gas production scheduled? Explain why or why not.*

When QGC sanctioned the QCLNG Project it undertook a thorough reserves assessment and concluded that it had, or would secure, access to sufficient gas in order to allow it to fully satisfy its existing domestic gas commitments and its LNG export commitments.

QGC supports the findings in the latest GSOO that in the near to medium term there is sufficient gas available in the Eastern Australian market to satisfy firm LNG sales commitments and anticipated domestic demand.

In an unconventional gas development, optimisation and refinement of the field development is an ongoing process, which is informed by production data and history matching of the subsurface model. Decisions about which fields will be developed, and in what sequence, and about how to optimise the performance of individual wells are continuously refined and optimised as additional data becomes available. Lessons learned from earlier phases of development are embedded in future investment and field development decisions.

QGC has drilled more than 2300 wells and is currently producing over 1000TJ's per day from its fields. The data derived from these existing and future wells will inform our ongoing field development decisions.

In addition, QGC has a portfolio of exploration assets and is actively exploring for gas to support further commercial development opportunities. We have invested in excess of half a billion dollars on exploration in the Cooper and Bowen Basins. We intend to remain an active and constructive participant in the Queensland gas industry over and above the QCLNG Project.

*Q3. Are there any factors that are restricting or limiting the ability or incentive for gas producers to explore for, or develop, new gas reserves? If so, explain.*

Over the past ten years, there has been a large increase in parties exploring for gas, particularly unconventional gas and frontier basins across Eastern Australia. This has been a direct response to the increase in demand for gas in Eastern Australia from linking to international markets - thus providing a greater incentive to explore.

The rate of activity has been affected in recent months by the global downturn in commodity prices. This has challenged the industry's ability to progress near term work programs.

Furthermore, the cost of exploring for and producing gas in Eastern Australia has risen considerably in recent years.

Whilst there has been some correction in costs in existing areas from the current downturn this is not readily transferrable to the frontier unconventional exploration sector where individual well costs can reach in excess of US\$50M.

There is also limited infrastructure available within Australia to develop a successful unconventional shale play. In an industry currently constrained by capital this creates a barrier to entry. Additionally, in an already very challenging environment, policies that restrict development (e.g. gas moratoria) or create duplications in environmental regulation create further disincentives to those looking to explore for gas.

*Q4. Does vertical integration of domestic gas producers with the LNG export projects materially affect the incentives of those or other gas producers to supply domestic gas users? If so, does this effect vary by location?*

We do not consider that the vertical integration of domestic gas producers with LNG export projects has decreased the incentives for those or other producers to supply domestic gas users. Rather, the development of the LNG projects has created the economic conditions for previously uneconomic gas to be brought to market. We note that QGC, and each of the other LNG proponents, has made commitments to the domestic market.

Where there is sufficient domestic demand at price and terms adequate to underpin investment, all producers, including any producers with vertically integrated LNG export operations, have clear incentives to develop their reserves to meet that demand.

The significant investment undertaken by the LNG projects to underpin infrastructure will help generate incremental opportunities to meet both domestic and export demand.

*Q5. Has the development of LNG export facilities created opportunities for gas suppliers to exercise market power in any location in Eastern Australia? If so, explain where and how.*

The development of LNG export facilities has changed the structure of the east coast gas market, most significantly through the linking of domestic prices to global prices and, in the short term at least, generated significant swings in supply and demand particularly in the Queensland market.

This is leading to an increased role for intermediaries. Historically, particularly for large industrial customers, there were more direct supply arrangements between producers and end users under bilateral point-to-point GSAs. These GSAs, once set, typically have little need to re-allocate risk so there is limited need for an intermediary to manage risk under these arrangements.

The increased complexity and uncertainty increases the risks and opportunities across the supply chain creating a greater role for intermediaries (such as large retailers and power generators with access to a portfolio of supply and offtake) who are better placed to manage the associated risks.

As indicated in Question 1, this is not a case of gas suppliers exercising market power. These outcomes are features of an industry in transition rather than a market characterised by a lack of effective competition.

*Q6. What factors affect the scope for inter-basin competition between gas producers in Eastern Australia? What are the circumstances in which such competition is viable and in which it is not viable? Provide examples.*

Pipeline access is an important element in facilitating inter-basin competition particularly in the short-term market. For example, the emergence of effective competition between the Wallumbilla and Moomba supply points is potentially limited by the current lack of access to short-term unutilised capacity at prices that reflect underlying supply-demand dynamics. QGC considers addressing this issue would increase the level of participation in the physical trade of gas (bi-lateral and exchange traded) and would also encourage other players such as intermediaries (who add liquidity) to join the market.

Refer to Question 37 and section – “Capacity Trading” for more detail.

## ACCESS TO PROCESSING FACILITIES

Q13. Is the cost of building new processing facilities or the ability to access existing facilities a significant barrier for prospective entrants? If so explain how and give examples of where this has occurred

The last five years has seen an over-heated market for resources, increased regulatory requirements, and the tightening of available capital which has significantly increased the cost of building new facilities. This makes new projects harder to justify.

While costs are softening in response to the downturn, the other two factors remain.

High development costs mean that, for the most part, new facilities are sized for the projected needs of the developer and there may be limited short-term capacity available for third party users. However, over time (and especially given the type curves associated with unconventional gas), access to this additional installed processing capacity may well become available to third parties to underpin satellite developments that would be uneconomic on a stand-alone basis.

Q14. Do owners of processing facilities have an incentive to provide third party access to spare processing capacity? Explain why or why not.

QGC supports the position endorsed by APPEA that commercial negotiation is the least cost and most effective method for achieving third party access to upstream facilities.

QGC and its partners have engaged with a number of third parties regarding provision of access to ullage in certain QCLNG gas and water processing facilities on reasonable commercial terms and these discussions are ongoing.

This can be quite complex as upstream facilities are designed for specific purposes, which may differ from facility to facility, particularly with respect to the processing of liquids and removal of contaminants, receipt pressures and gas specification. However, this is generally within the remit and capabilities of the parties to resolve by negotiation.

Q17. Do gas specification requirements materially affect the supply of gas for different users? Is any divergence of gas specifications between Queensland LNG and other uses act as a barrier to trading gas within Eastern Australia (e.g. due to processing cost differences)? If so explain how.

The LNG projects do have specification limits which are more constrained than the national gas pipeline specification. Furthermore, individual specification limits are not common across the LNG projects as they reflect the initial view of the requirements of each project at the time of development.

QGC has been working with the other LNG proponents and their key service providers to revisit and determine the broadest specifications capable of being processed through each plant so as to remove impediments to moving gas, particularly of CSG quality, between the projects.

For non-CSG supplies, there remain some specification limits which are not acceptable for processing within the LNG trains under certain operating conditions. QGC and other proponents have worked actively with third parties, including pipeline owners, to implement a regime that manages this risk and reduces any impediments to supply across the broader network.



Note the production from the CSG fields meets the National Gas specification so there is no impediment for flow to domestic markets.

## NEGOTIATIONS OF NEW GAS SUPPLY AGREEMENTS

*Q18. Have industry participants encountered any difficulties in obtaining offers of gas supply, or been involved in any failed negotiations for gas supply? If so, describe the negotiation, providing comments on what concerns arose about the process of negotiation and how this was different to previous negotiation.*

QGC has recently entered into a variety of commercial arrangements to manage short and long positions. This includes a number of bi-lateral MSAs with third parties (producers, LNG projects, retailers, large industrial and power generators), which enable the ability to buy, sell or swap gas under subsequent transactions at short notice.

In negotiations for the purchase of natural gas, QGC has not experienced significant issues with obtaining proposals. There have at times been some unrealistic expectations with regard to price but these have been dealt with in the normal course of commercial negotiations.

QGC has been approached by some parties to purchase firm gas in the near-medium term. The most recent long term domestic Gas Supply Agreement (GSA) QGC entered into was in 2013. While QGC has not been in a position to reach agreement with parties for additional firm/term GSAs across this period given uncertainty over facility start-up timing, we are seeking to put in place MSAs with interested parties. These agreements provide benefits in reducing the costs associated with short-to-medium term transactions.

## DOMESTIC GAS PRICES

*Q21 What are the key factors currently affecting the price of gas in Eastern Australia? Are current prices expected to be transitory or likely to be sustained? What information is most important to informing your view?*

In all likelihood prices will be cyclical, although the traditionally low-priced foundation GSA terms are unlikely to be sustained.

Domestic gas prices will ultimately be determined by supply and demand over the long term and will be influenced by a number of factors including the availability of reserves, the cost of production, the capacity to pay, transportation cost, level of service, technological advancement, competing fuels, carbon pricing, LNG netback and the exchange rate.

The predominant factor in the medium term is likely to be the cost of production. The cost of developing future reserves and current development moratoria will also place pressure on gas prices compared to historical levels.

The market has been traditionally well served by relatively low cost gas produced from liquids rich fields which cover a significant proportion of the infrastructure cost base. As the Cooper and Gippsland Basins mature and associated liquids production declines, the increased cost of producing replacement gas reserves from those Basins will no longer be subsidised by the revenue generated by sales of liquids to the same extent.

If gas is required from more remote basins to meet demand then infrastructure costs are likely to be a large component of the end use gas price.

On the other hand the market for gas on the east coast (outside of the LNG projects) is actually quite small. A significant near market discovery (c1-2tcf) in the Otway would likely have a significant impact on supply to the southern markets and therefore price.

*Q23. Is there an appropriate reference price for gas in Eastern Australia? Is one necessary? What are the pros and cons of different reference prices?*

There are a number of locational reference prices in the east coast gas market, with varying degrees of usefulness to market participants. The reference prices in existing facilitated markets do not always demonstrate a correlation to underlying supply and demand. The reference prices in the Short Term Trading Markets (STTM) and Declared Wholesale Gas Market (DWGM) in Victoria are typically set off thin trading volumes. They tend to have a strong correlation to underlying contract prices and so are not necessarily reliable indicators of a price at which gas can be bought and sold.

These markets have limited active participants, which further reduces their ability to provide suitable reference prices for larger transactions. Furthermore, the current market design (e.g. lack of workable capacity trading etc) may enable current players to influence price outcomes. As both the number of participants increase and the underlying positions become more diverse, liquidity will increase and the reference prices will be more helpful.

The Wallumbilla GSH is potentially a current exception. If liquidity grows at this point, we would expect price to reflect short and long positions around the hub.

Refer to Question 34 for more detail.

*Q24. Are buyers that enter into oil-linked gas supply agreements able to effectively hedge their exposures to changes in oil prices? If so, how? If not why not?*

There are a number of intermediaries who will provide a hedging service for oil-linked products. This can be achieved in a number of ways including agreeing to a hedge at an agreed strike price, or obtaining an oil price/CPI swap.

The introduction of oil-linked pricing into GSAs will likely lead to participants taking different views with regard to managing this exposure, which will in turn create more liquidity in short term markets.

## INFORMATION AVAILABILITY AND TRADING

*Q30. Is there adequate information publicly available about production capacity to supply LNG and domestic users? If not, what key sources of information are missing and what kind of issues does this create for market participants.*

In terms of a medium to long-term outlook, current information sources (e.g. GSOO, Gas Bulletin Board (GGB) and state government reporting of reserves) provide a sufficient and reasonable level of information on the east coast supply-demand balance. In contrast, more significant changes are necessary in relation to shorter-term information provision. The approach needs to shift from previous day infrastructure reporting (e.g. production at processing plants, pipes and storage) to a platform that captures data that is relevant to domestic gas trading and managing commercial positions.

As a start, more frequent (real-time) reporting of entry and exit gas from the LNG systems would more appropriately inform the market of immediate supply-demand changes and enable participants to respond accordingly. Similar models are core elements of mature gas markets in Europe and the United Kingdom. QGC has developed a “real-time delivery and receipt point” model that captures these features within our system and this approach could be applied more broadly on the east coast.

We understand the Australian Energy Market Commission (AEMC) is proposing to initiate a process to establish the GBB as a “One-Stop Shop” for east coast gas market information and in part will examine issues such as reporting structures and frequency. QGC supports the continuation of this process.

*Q31. What information do gas users need for the purposes of being able to confidently engage in gas supply negotiations? How would it be used?*

The development of a credible published benchmark price would appropriately inform all players when formulating expectations of short and long-term price movements. Argus currently reports a Wallumbilla index and AEMO publishes an “end-of-day” benchmark price for the Wallumbilla GSH. While these sources provide an indication of where the market is currently transacting, for a reference price to meaningfully inform long-term negotiations, it needs to be based off a sufficiently liquid market (i.e. exhibits tight bid-offer spreads and where executed trades have only a minimal impact on prevailing price), and support the establishment of a forward curve.

The focus for policy makers should be on developing the right market frameworks (e.g. improved access to short-term capacity, information provision and hub services) that will support increased trade and as such the reliability of the already quoted prices rather than mandate the reporting of further price indices. This would “crowd out” private operators in the provision of these services and additional price sources will add to market uncertainty.

Refer to Question 33 for more detail.

*Q32. Does information asymmetry between gas suppliers and gas users have a significant effect on gas supply negotiations?*

We do not consider this to be an issue given the level of publicly available information. Rather, we believe the proposed changes to information disclosure requirements for LNG proponents will require a level of disclosure that extends beyond what is required by other parties trading and shipping gas in the east coast gas market - thereby creating information asymmetry and potentially disadvantaging LNG proponents.

Specifically, these proposed changes will require the publication of individual LNG export pipeline flows. QGC, together with the other LNG proponents proposed that aggregation of LNG export pipeline information would provide an appropriate level of disclosure. It informs the market of any overall change in LNG supply-demand position without comprising individual commercial positions. The arguments for disaggregated LNG pipeline reporting do not appear to be based on any demonstration of how it will directly improve business, operational and risk management decisions or assist in achieving broader policy objectives.

In considering information provision, in the east coast gas market, it is necessary to ensure it appropriately informs the market, supports exchange based and bi-lateral transactions while avoiding commercially disadvantaging individual parties.

*Q33. To what extent does the lack of a widely accepted external reference price affect market outcomes in the supply of gas in Eastern Australia?*

It is limiting or delaying the timing of bi-lateral transactions in terms of agreeing price and impacts players differently depending on their position. Aggregators and vertically integrated players are likely to be less impacted, as they have positions across the system. Industrial customers, however, who operate at a single point, are likely to receive greater benefit from being able to access a benchmark price. An externally reported price has the ability to give these parties greater comfort in entering into transactions. If a suitable reference price was available it would promote more use of standardised agreements and reduce cycle time. It would also assist in enabling the future market to trade.

Refer to Question 23 for more detail.

*Q34. Do facilitated trading markets currently provide a sufficient level of flexibility to market participants to manage risks and uncertainty in the changing market circumstances? To what extent are they likely to do so in the future?*

QGC views the Wallumbilla GSH, operated by AEMO, as central to promoting liquidity in the east coast gas market and as such providing short to medium flexibility to participants to manage risk. The Wallumbilla GSH, however, currently lacks liquidity and depth and its development should proceed on the basis of encouraging participation, increasing volume traded and minimising price movements. Key limiting factors include the lack of:

- Access to short-term competitively priced pipeline capacity;
- Relevant and frequent market information;
- Necessary hub services; and
- A within-day market.

Each of these points is specifically addressed in other sections of this response.

*Q35. To what extent are the pricing outcomes observed in facilitated trading markets likely to be relevant to future negotiation of long-term gas supply contracts?*

Refer to Question 31

*Q36. Is the further development of existing or additional facilitated trading markets likely to result in better outcomes for market participants? If so, how?*

With respect to a new pricing location such as Moomba, QGC supports the active encouragement of new participants/customers into the Wallumbilla GSH (as opposed to creating new pricing points). Moomba is an obvious delivery point for southern based end-users to access supply or supply from Gippsland/Bass Strait Basins. There are, however, a range of factors that have not necessarily been considered in sufficient detail to suggest it is the optimal long-term solution for the east coast gas market.

While a Moomba hub may appear a simple, logical and appropriate response for increasing participants' access to supply, it does change the nature of the market and trading dynamics. Given the size of the east coast gas market and at this stage in its development, there is significant benefit in concentrating trading/liquidity at one trading point (e.g. Wallumbilla). This will provide sufficient depth to enable the establishment of an efficient reference price, which is necessary if the Australian Stock Exchange (ASX) proposed futures contract market is to be successfully traded. Increased trading at one point narrows the bid-offer spreads and the overall price movements between trades, which is a standard indicator of liquidity. Developing an effective futures market is in the long-term interest of all those who sell and consume gas.

QGC considers that if other aspects of market development are adequately addressed (e.g. access to competitively priced short-term capacity) the necessity for an additional hub(s) reduces and there might be other design options that lift the overall level of liquidity at Wallumbilla (which has the potential to develop into the key physical and financial trading point). QGC has suggested rather than establishing a new pricing point at Moomba, Moomba becomes a new GSH delivery/receipt point and trades are referenced to the Wallumbilla price.

We understand this issue forms part of the AEMC Wholesale Gas Market and Pipeline Frameworks Review and we await the outcomes of this process.

*Q37. To what extent are international comparisons relevant to the supply of gas and associated services in Eastern Australia? Are there any lessons from reforms in the US, the EU or elsewhere that may be relevant for Australia? What reforms or measures adopted in the US or the EU are not likely to work in Eastern Australia, and why? Are there any intermediate trading models between the US/EU trading markets and bilateral contracting that could improve information flow and increase trading liquidity in Eastern Australia?*

Historically, the east coast gas market was characterised as relatively small and stable. The establishment of LNG industry, however, has changed the market dynamics. Pricing is linked internationally and the introduction of the LNG facilities within the east coast system means that event-driven changes in LNG plant feedstock demand will impact the domestic supply-demand balance.

To ensure that available gas is able to flow to where it is needed most, we must look to other mature and internationally linked gas markets to inform how the east coast should evolve. There are key learnings from overseas markets in terms of pipeline capacity management, hub development and market information.

For example, in terms of pipeline congestion management, the European gas market faced similar challenges during the last decade and in October 2013, saw the introduction of a market-based mechanism that effectively ensures the release of unutilised short-term pipeline capacity to the market. This was effectively implemented, by the European Regulator (ACER) as part of the Congestion Management Principles (CMP), which included a specific “anti-hoarding” mechanism referred to as the “Over-Sell and Buy-Back” mechanism (the OSBB).

It has been operating in the United Kingdom since 2002 prior to its broader application in Europe. It requires available pipelines to make day-ahead “firm” capacity available through an auction mechanism at market reflective prices. We believe the principles and objectives underpinning the OSBB are very relevant in the Australian context. It represents a good starting model to illustrate how a market-based solution could be developed for the east coast gas market. Its key features include:

- Applied in situations where a pipeline is fully contracted, but under-utilised on a day-to-day basis by existing shippers (i.e. the pipeline is “contractually” congested rather than facing physical constraints).
- Encourages the secondary trade in capacity ahead of the mechanism being applied and provides a commercial solution to the allocation of capacity when physical constraints occur.
- Pipelines retain the revenue from the “over sell” auction, which also funds any “buy-back” requirement. This provides incentives for pipelines to seek commercial opportunities.
- It has a number of features that make it attractive for the east coast gas market including the ability to be overlaid across an existing market arrangement and it does not expropriate the rights of primary capacity holders with long-term contracts (only short-term capacity forms part of the “buy-back” auction).

We do note implementation within the east coast gas market would require consideration of its operation within the existing regulatory framework, the treatment of existing contracts and risk mitigation measures for pipeline owners. We expect the AEMC East Coast Wholesale Gas Market and Pipeline Frameworks Review to explore these issues and recommend targeted solutions



appropriate to Australia. Overseas markets also provide guidance on relevant information provisions and hub development.

## OWNERSHIP AND REGULATION

*Q40. Have users observed an increase in the price of pipeline services or deterioration in the terms on which pipeline services are provided? If so, to what extent is this due to increased concentration in ownership of transmission pipelines, decreased economic regulation or other factors? Provide specific examples of changes to prices/terms over relevant period?*

Some transmission pipeline services costs do not appear to be directly linked to the cost of providing the relevant service.

For example, while the re-nomination charging arrangements are a function of a number of factors, “with-in day” variation costs can potentially be ten-fold higher than the value paid for a “day ahead” change. This would appear to be significantly in excess of the marginal cost of providing the service.

It is difficult to ascertain how these service charges are determined and specifically how they reflect the underlying costs borne by the pipeline owner of making “within-day” changes. In part, this is preventing the establishment of a “within-day” market, which would greatly assist the market to respond to intra-day changes in LNG plant operations and or divert gas to higher value markets such as the National Electricity Market (NEM) in the short-term.

Refer to Question 43 for more detail.

*Q41. With so few transmission pipelines now covered by economic regulation, does the threat of coverage still place a constraint on pipeline owners' behaviour?*

We support the continued operation of the contract carriage model for pipelines outside the DWGM in Victoria and the overall approach to avoiding unnecessary infrastructure regulation (where it is observable that outcomes reflect those of a competitive market). We recognise this has allowed for point to point pipeline development underpinned by foundation shippers.

There does, however, appear to be a general view that the current regulatory framework (i.e. largely uncovered pipelines) is an “ingrained” element of the market structure and unlikely to change. This is supported by an observable acceptance of the continuation of the existing regime by regulators. While this model provides overall net benefits, some aspects could be resulting in inefficient outcomes, which require targeted consideration. Specific issues include contract terms covering re-nominations, imbalances and importantly the pricing of short-term “as available” capacity.

## PIPELINE SERVICES

*Q42. Are pipelines being developed or enhanced to meet producer and shipper needs? Please provide examples of experiences in securing changes to pipelines to meet changes in supply and demand for gas.*

Overall pipeline development/investment is progressing in line with the needs of the market. In response to expected changes in gas flows due to the entry of the LNG export industry incremental pipeline investments have proceeded without the need for regulatory intervention or government support. This is in the form of bi-directional/reverse flow capability upgrades on relevant pipelines (e.g. Roma to Brisbane, the South-west Queensland and the Berwyndale to Wallumbilla Pipelines). These changes directly enable gas to enter and exit the LNG systems as required. The immediate challenge is ensuring the efficient allocation of short-term unutilised pipeline capacity.

*Q43. Are pipeline services (including emerging pipeline hub facility service requirements in Wallumbilla) adequately evolving to meet user requirements? If not, explain which services are lacking on which pipelines and the effect of that on users.*

Central to delivering greater flexibility in the market is enabling improved “within-day” access to unutilised capacity, renomination capability and imbalance management. A range of issues exist with the current market design including:

- **Limited access to competitively priced short-term firm capacity**  
This is a significant issue and discussed in detail in Question 37 and under the section – “Capacity Trading”.
- **Inadequate renomination and imbalance management** - The arrival of the LNG export industry changes the nature of the market from a small and stable demand base where the current day-ahead balancing approach was appropriate to one which will see “within-day” demand changes larger than the size of the domestic Queensland gas market.

As mentioned (Question 40), the establishment of “within-day” trading flexibility is essential to allow further balancing, increasing liquidity and the overall development and growth of a well-functioning east coast gas market. This capability is necessary to enable participants to respond to “within-day” changes in supply and demand. For example, an unplanned LNG facility outage could result in excess gas being made available to the market. We are not convinced that the current arrangements enable a gas-fired generator to source this additional gas in time to respond to higher than expected evening peak demand.

Currently, re-nominations charges are essentially prescribed by pipeline owners and in QGC’s experience the ability to re-nominate “with-in” the gas day is cost prohibitive. These costs are higher than we would anticipate and are not necessarily a reflection of the true costs incurred by the pipeline operator. We also understand that different nomination “cut-off” times may apply across various shippers. This could advantage some players with “later” nomination requirements and limit competition in the “day-ahead” market.

Equally, the manner in which imbalances are managed is likely to be limiting the level of intra-day/balance of day trading. From our experiences there are insufficient incentives on pipelines to optimise imbalances “within day” and to allow for greater delivery of “within day” firm gas. It is also unlikely that imbalance changes are being optimally allocated to customers and there should be a move to customer netting across pipelines.

- **Hub services** – With regards to the Wallumbilla GSH, QGC views this as central to promoting liquidity in the east coast gas market and supports its continued development. Critical to this is the development of a single Wallumbilla hub product. As a principle, in order to support the development of a traded futures/Over-the-Counter (OTC), market we recognise the importance of developing a single Wallumbilla product underpinned by a hub design that delivers a “firm” level of service. We note AEMO has commenced a work programme and QGC is actively participating in the process.

*Q44. Are there any restrictions or limitations on the supply of specific ancillary pipeline services that are affecting competition in the supply or acquisition of gas? Do restrictions or limitations vary by location or by pipeline owner?*

QGC has not identified any major concerns.

*Q45. Is the level of available information on gas flows sufficient to support competition across pipeline services? Provide any examples where timely availability of information on gas pipeline conditions would have influenced which pipeline was used to transport gas. What are the costs/barriers to providing more disaggregated information?*

Significant informational improvements (including pipeline data) are necessary to appropriately inform the market of real-time system changes. As referenced in Question 30, processes focusing on this issue are likely to commence as part of the AEMC Wholesale Gas Market and Pipeline Frameworks Review. In reviewing pipeline information, confidentiality needs to be considered and additional informational requirements should avoid unintended consequences such as commercially disadvantaging individual parties. With respect to costs, we are not of the view that the move to real-time reporting should impose significant additional costs on pipelines. In all likelihood, pipelines should already be collecting this information through their systems.

*Q46. To what extent is the 15 year no-coverage determination (the so-called Greenfields Incentive), a useful driver of pipeline investment? To what extent is it a restriction on access to pipelines?*

The QCLNG pipeline (which was recently been sold to APA and now referred to as the “Wallumbilla to Gladstone” Pipeline) is subject to the 15 year no-coverage exemption. As developer and initial owner, we recognise the direct benefits such an exemption provides in facilitating investment and endorse the continuation of this arrangement to support large scale capital intensive investments. To date, we are not aware of any third party access concerns resulting from the no-coverage determination.

## TERMS AND CONDITIONS FOR GAS TRANSPORTATION

*Q47. Are there contractual terms and conditions in gas transportation contracts that are limiting competition in the supply of pipeline services (including secondary trading of capacity)? If so, explain what those terms are, the rationale for them and their effect on pipeline users.*

Refer to Question 54

## PIPELINE CAPACITY TRADING

*Q48. Are you aware of any instances where pipeline capacity was sought, but not made available or alternatively not able to be procured in time? Provide details, including whether that capacity was sought from pipeline operators or operators.*

QGC considers that ‘capacity hoarding’ by shippers is evident in the east-coast gas market. Through the management of capacity, price differences between markets have emerged, which do not necessarily reflect the underlying supply-demand conditions. Furthermore, our own participation in the market suggests there are difficulties in accessing competitively priced short-term capacity.

Refer to Question 37 for details on the OSSB mechanism introduced in Europe as an illustration of a mechanism that could be considered to address these issues.

*Q49. To what extent are the new capacity listing platforms offered by APA and Jemena, or the current rule change proposal to the AEMC to enhance capacity information, likely to assist in the development of efficient capacity trading? If so, how?*

The development of IT platforms could reduce search costs and provide greater transparency on the level of secondary capacity trading. Without, however, specific measures to bring unutilised capacity to market, there is unlikely to be any significant trading activity taking place. While the listing platforms are necessary to facilitate trade, they are insufficient on their own to promote the active trade in secondary in pipeline capacity. Similarly, improved information on pipeline shippers could result in more contact between potential counter parties, but not necessary result in additional executed trades.

*Q50. To what extent, or under what conditions, are the ‘as available services’ offered by pipeline operators a substitute for capacity trade entered into with a shipper? If not, provide reasons.*

If a party is seeking short-term/day ahead firm capacity, the “as available” service offered by the pipeline operator is no different in terms of the service that could be traded directly with a shipper. The pricing structures are, however, likely to be different. It is quite typical in Eastern Australia for pipeline owners to charge a premium above the firm service for an “as available” service for unutilised capacity. You would expect the “as available” service to be offered at a discount to the long-term price. This is not a common factor in more liquid more developed markets.

Pipelines have commenced posting “as available” capacity on their listing sites. This is at a fixed price (which does not necessarily reflect underlying short-run supply-demand dynamics), whereas under a bi-laterally executed traded between shippers price would be a negotiated outcome.

Refer to Question 52 for more detail.

*Q51. How effective is competition between shippers and pipeline owners for the provision of contracted, but unutilised capacity? If it is not effective, what factors are impeding competition?*

Currently there is no or very limited competition between shippers and pipeline owners in the provision of contracted, but unutilised capacity. Neither the pipeline owner nor the shippers are particularly incentivised to sell available capacity. QGC believes there are various impediments to short-term trading in pipeline capacity. Through our experience, shippers are not releasing this capacity for various reasons including:

- **Potential lack of market awareness** - at a practical level, given the previous small and stable nature of the market, shippers could be potentially unaware of the level of potential interest by other parties in purchasing secondary capacity.
- **Transaction costs potentially exceed the value of sale** – the bi-lateral nature of transacting for pipeline capacity is a slow, resource intensive and a relatively costly process. Issues of credit, payment, liability, dispute resolution and default conditions, physical delivery and gas quality and other specific terms need to be agreed. Historically, it facilitated long-dated transactions involving sizable volumes. By comparison, in an unconstrained physical system, we would expect short-term capacity clearing prices to be relatively low. For this reason, current arrangements are not a particularly effective model for enabling short-term transactions. Developing some form of a facilitated market, which brings down these costs, is the first step in promoting any measurable short-term shipper to shipper capacity trading.
- **Maintains flexibility and avoids nomination complexities** - shippers may also be incentivised to forgo revenue from capacity sales (if the transaction value is relatively low) in preference for maintaining operational flexibility. The added complexity to work through the re-nomination process may also act as a practical disincentive to transact.
- **Potential commercial opportunities** – Through the management of capacity, price differences between markets may emerge or be extended, which do not necessarily reflect the underlying supply-demand conditions.

Pipeline owners also have a role to play in facilitating the short-term trade in unutilised capacity. Some pipelines do list day ahead (and longer-term) “as available” capacity for sale, however, it is not traded extensively. In our view this is not necessarily due to a lack of interest, but the price at which it is offered to the market. See Questions #50 and #52.

*Q52. Are the prices charged for capacity trades and 'as available services' what you would expect to observe in a workably competitive market?*

While pipeline owners post capacity on their listing platforms, it is offered at specified published prices, which do not reflect near-term market conditions. Under a "workable competitive market", we would expect capacity to be made available at floating prices more reflective of dynamic short-run supply and demand conditions.

The current arrangements are creating a situation where the commodity price, reflecting short-run supply and demand conditions, can drop below published transportation offers. For example, if the downstream market price for gas is \$1.30/GJ, and the short term value is \$0.50/GJ (e.g. at the hub), purchasing capacity at a fixed price of \$0.95/GJ to deliver the gas, means the seller would make a loss on the sale. In this circumstance, the short-term value of trade is not being maximised. It is our understanding that this is likely due to the operation of contractual agreements between the pipelines and existing firm capacity shippers.

*Q53. How should available pipeline capacity be measured?*

This is a very technical issue and QGC considers that this question is best considered by the AEMC through the COAG Energy Council's Rule change request and East Coast Gas Wholesale Gas Market and Pipeline Frameworks Review.

*Q54. Are there any provisions in gas transportation agreements which limit or impede effective capacity trading? What are those provisions and how do they work to limit or impede capacity trading?*

Anecdotally, QGC understands that contractual provisions may exist that restrict the price at which pipelines can offer capacity to the market (i.e. if secondary capacity is offered to the market at prices below the long-term contract price, existing shippers are also entitled to adjusted pricing for shipped volumes(i.e. most favoured nation clauses).



## STORAGE

*Q56. Are there adequate levels of storage in Eastern Australia? Does the market provide adequate locational and investment signals for adequate storage? If not why not? Would new storage assist in supply, including during transitional and peak periods? If so, where would it be placed?*

Eastern Australia has limited storage available and development of further storage would be welcomed. QGC does not perceive this to be a result of any failure of the market to provide signals, rather an historical overlay from there being an abundance of processing capacity by foundation suppliers to meet demand, particularly in Victoria and a lack of willingness to price a “swing gas” service.

There are also limited suitable fields capable of being converted to storage where they can provide utility to the market. In recent times where fields have been available such as Silver Springs and Roma these fields have been developed. In absence of a suitable reservoir AGL has proceeded with the Newcastle LNG facility.

In addition to physical storage, parties have been entering a variety of commercial agreements that utilise portfolio flexibility in a way to provide virtual storage (e.g. time swaps, park and loan, call-backs).

*Q57. Are there adequate opportunities for third parties to access storage facilities? Do third parties have sufficient information to negotiate access on reasonable terms?*

QGC is not aware of any impediments to accessing storage.