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10 September 2015

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY NSW 1234

Via online submission

Dear Mr Pierce

WHOLESALE GAS MARKETS DISCUSSION PAPER

Thank you for the opportunity to comment on the Commission's Wholesale Gas Markets Discussion Paper. The Australian Pipelines and Gas Association (APGA) sets out our response to the questions posed by the Commission in the attached submission.

In considering the issues and concepts presented by the Commission, APGA has reached the view that a series of physical, voluntary hubs could be developed to enhance liquidity in the existing market without significant changes to the current regulatory settings. A version of concept 1, with supply hubs at Wallumbilla, Moomba and in Victoria and supported by voluntary balancing markets in Victoria, Sydney, Adelaide and Brisbane, could encourage increased liquidity of marginal gas at these central locations which, with increased supply, could develop into a meaningful secondary market.

APGA looks forward on working further with the Commission as the Stage 2 workstreams of Commission's Review of the East Coast Wholesale Gas Market and Pipelines Framework progresses.

Please contact me on (02) 6273 0577 or sdavies@apga.org.au to further discuss any positions in this submission.

Yours sincerely

Steve Davies
National Policy Manager

Wholesale Gas Markets Discussion Paper

AEMC Reference: GPR003

10 September 2015

Contents

Key points

- Gas trading markets are effective in efficiently allocating marginal gas. Their primary utility in the Australian context is to provide market participants with flexibility to manage the volume and price risks of their primary contracting arrangements.
- Physical hubs are preferable to virtual hubs as virtual hubs have to make assumptions regarding system capabilities that are not reflective of physical flows and constraints. Further, virtual hubs are likely to require regulatory intervention into existing commercial arrangements.
- Voluntary hubs are preferable to compulsory hubs as they appropriately allocate the cost of services to the parties that use the services.
- Both virtual hubs and compulsory hubs generate false liquidity, adding costs to participants while delivering limited benefits.
- The structure of the Eastern Australian gas market is the major limiting factor to its liquidity. High-level HHI analysis suggests a level of concentration in production that makes it very difficult to develop liquid markets. The level of intervention required to increase the number of participants, address the concentration of market power or increase the volume and/or location of gas demand is almost certain to be too costly.
- **APGA considers that a series of physical, voluntary hubs could be developed to enhance liquidity in the existing market without significant changes to the current regulatory settings. A version of concept 1, with supply hubs at Wallumbilla, Moomba and in Victoria and supported by voluntary balancing markets in Victoria, Sydney, Adelaide and Brisbane, could support increased liquidity of marginal gas at these central locations which, with increased supply, could develop into a meaningful secondary market.**

Introduction

The Australian Pipelines and Gas Association (APGA) welcomes the opportunity to provide comments on the Australian Energy Market Commission's Wholesale Gas Markets Discussion Paper. The conceptual designs for future wholesale gas markets in Eastern Australia have consequences for all gas market participants and APGA has views on many of the issues raised by the Commission.

APGA considers the Commission has provided excellent analysis on the factors that contribute to a liquid market. This type of analysis has been lacking in previous reviews, including during the development of the CoAG Gas Market Vision, which calls for the establishment of a liquid wholesale market without assessing whether such an outcome is possible given the Australian starting conditions.

The Wholesale Market workstream is consulting on the design of the wholesale gas market that should be the focus of market development over the long term. In reaching a preferred concept, it is necessary to consider any changes that may be required in gas regulatory regimes to enable the concept. It is then possible to assess whether the potential benefits accruing from a concept outweigh the costs associated with regulatory changes necessary for its implementation. It is important that the work of this stream be mindful of which concepts are within the bounds of Australia's competition policy, which adopts a specific, intentional approach to access and competition. Whilst 'thinking big' will require the Commission's conceptual work to step outside these boundaries, in all likelihood deliverable concepts lie within the boundaries. With regard to concepts requiring changes to pipeline access arrangements, the Productivity Commission stated in its March 2015 Research Paper *Examining Barriers to More Efficient Gas Markets*:

Gas market stakeholders have proposed changes to the way capacity is allocated under the contract carriage model. There have been proposals to extend the open access principles that apply under the market carriage model, and calls for the introduction of mandatory pipeline capacity trading provisions that apply in other countries.

In the Commission's view extending elements of the market carriage model could put at risk the investments needed to efficiently respond to current and future market developments. There would also be significant risks from adopting mandatory pipeline capacity trading provisions that apply in other countries, especially if such provisions involve the over-riding of private property rights.[1]

[1] PC, Examining Barriers to More Efficient Gas Markets, p105, March 2015

The Commission has posed broad questions for consideration in this Discussion Paper. APGA has answered each but has found there are elements of some responses that are highly relevant to other questions.

Interaction with other workstreams

Before commenting on the issues set out in the Discussion Paper, APGA notes that many participants in the Commission's Review are making a link between the Commission's Wholesale Market workstream and the Capacity Trading workstream. A common position seems to be that the two streams are inextricably linked. APGA takes a different view. The Capacity Trading workstream will consider the materiality of current issues accessing secondary capacity and the suitability of certain mechanisms to address access in current market circumstances. This is in line with the Commission's updates on this work to date. APGA considers the focus of this workstream to be more immediate than the Wholesale Markets workstream. From APGA's perspective, there should be no limitation on the Wholesale Markets workstream contemplating conceptual designs without iterative reference to the outcomes of the Capacity Trading workstream.

Interaction with the ACCC East Coast Gas Inquiry

The Commission has provided a useful set of gas market metrics in table 3.1 that APGA considers appropriate for analysis in the East Coast gas market. With regard to the market health metrics, it is to be expected that the ACCC East Coast Gas Inquiry will be assessing the state of competition in wholesale markets with a similar set of criteria. It is appropriate that this forms part of the consideration of concepts – there is little point in recommending a model that requires major regulatory intervention, with associated high costs, if it is unable to deliver great benefits due to the underlying market health. Whilst the Commission and the ACCC are in close communication, it should be recognised that it could be difficult for the AEMC to deliver its final view on future wholesale markets in advance, or concurrent to, the ACCC delivering its final report to the Federal Government.

Response to Questions

1. Over the next 10 years, how do industry participants see their gas sales and procurement activities changing?

APGA observes that there are divergent trends.

The recent massive investment in new LNG export facilities has meant there is strong and dominant demand for long-term gas supply for those plants. While the facilities have, for the most part, secured their own supplies, they are also looking to the existing supply basins (such as Gippsland) to augment those supplies. In addition, it would appear that, while domestic shippers would also like to replace their existing but expiring long-term gas sales agreements with new long term arrangements, price and uncertain availability mean that these shippers appear to only be able to secure short-term arrangements at acceptable prices.

Meanwhile, opportunities in the short-term trade of gas have increased, in particular for 'ramp up' gas and potentially to respond to problems with the LNG facilities once they are up and running. These opportunities are likely to remain at the margin, providing opportunities for market participants to balance the volume and price risks of long-term contracts with short-term, flexible options. The exception appears to be in the activity of small industrial users, who are increasingly interested in using facilitated markets to reduce their reliance on retailers. Whilst the first movers may be able to use facilitated markets in this way, it remains to be seen if this is a viable option for all small industrials, particularly as retailers will be delivering less gas to facilitated markets as small industrials move away from existing supply arrangements.

If the market experiences a general trend towards contracts decreasing in length, there may be reduced volume and price risk that needs to be actively managed through secondary markets.

2. Do the current market arrangements adequately support participants' needs?

Most commentary indicates there are issues securing gas supply agreements for gas supply in 2017 and beyond. It is unlikely that market development focussing on hubs and increased liquidity will address issues in the contract market. It certainly will not address them before 2017.

It should be noted that gas transmission companies are delivering the investment required to meet shipper needs. This includes pipeline expansions, interconnections and developing bi-directional capability. In addition, new services and capacity trading platforms have been developed to provide additional flexibility.

3. Are gas trading markets expected to become more important in ensuring the efficient allocation of gas?

The role of contracts in the efficient allocation of gas should not be understated. Contractual agreements are an essential risk management tool that provide firm commitments to both seller and buyer, manage demand risk for investors in gas supply projects and manage supply risk for investors in gas demand projects. APGA notes that all gas markets feature heavy use of contracts. As do the majority of commodity markets.

Unsurprisingly, it is appropriate to consider the gas supply market in terms analogous to the gas transportation market. In both, there are primary and secondary markets. In the primary market for each, firm commitments are made to efficiently allocate risk appropriately between buyer and seller. In both, the secondary market plays a role in managing the risks, such as volume and price risk, inherent in long-term, firm commitments. In the gas supply market, gas traded in secondary markets is often termed 'marginal gas'.

Gas trading markets can be important in ensuring the efficient allocation of marginal gas. This is the case in the current Eastern Australian gas market, where the existing trading markets, such as the STTMs, are slowly maturing to the point that multiple market participants are actively managing marginal gas requirements and very small participants are managing some primary supply requirements. The Wallumbilla Gas Supply Hub has had a successful start and can be expected to further mature.

Marginal gas requirements take different forms for different market participants. It is the extra gas a power generator needs to take advantage of high electricity prices. It is the gas not required by retailers because the weather was warmer than forecast or the extra gas required because the weather is colder. It is the difference between the 1-in-2 peak day and the 1-in-20 peak day. It is the gas not required by a user due to routine or unexpected maintenance activity.

For more sophisticated participants, secondary gas markets can enable participants to more actively manage price risk, taking advantage of cheaper gas in trading markets to reduce their requirement for primary gas.

APGA notes that, for the most part, producers play very little role in existing trading markets apart from the Wallumbilla Supply Hub.

The question becomes, **can there be sufficient marginal gas to underpin market liquidity to the extent trading markets play a material role in primary supply arrangements?**

As the Commission has noted, there needs to be a self-reinforcing loop of growing market liquidity for markets to develop to the point where financial products can emerge. The same self-reinforcing loop is vital to the development of markets to the point where they can play a role in supporting, or even displacing, market participants' primary gas requirements.

It is most likely that gas available to trading markets will continue to be, as it currently is, the gas for the balancing requirements of retailers, exporters and users who are buying and selling gas through contracted agreements. This is the basis on which the existing hubs are built.

Note that this would be true even if the gas supply hubs or virtual markets were compulsory or gross markets like the STTM and DWGM. As the AEMC observed, these markets, while gross in nature, in effect only trade at the margins – gas volumes through these markets present a level of 'false liquidity' where participants often trade with themselves. Experience shows that increased volumes do not automatically lead to increased trading. It is also necessary that the market settings and structure (number and dominance of participants) is conducive to increased trading.

The level of marginal gas available to a trading market will depend on both the volume available and the number of participants.

When a market observer considers the existing forecasts for gas demand over the next 10 years, it is difficult to reach the conclusion that the gas market is likely to have more participants than it currently has or that, outside of LNG demand, there will be an increase in gas demand.

Unfortunately, there is the real prospect that the future East Coast gas market will have fewer participants. The Commission would be well aware that AEMO's 2015 Gas Statement of Opportunities and 2014 National Gas Forecasting Report both forecast declines in industrial and gas-fired generation usage to the extent that the best case scenario is a 15% reduction in domestic demand.[2]

[2] Domestic demand excludes export demand.

Forecasts in AEMO's 2015 GSOO indicate the East Coast gas market will see less gas used in electricity generation, large and small industrial facilities. Direct market participants such as power generators, retailers and industrial users will use less gas. This will reduce the amount of marginal balancing gas requirements of each participant, leading to lower volumes in many markets. Some market participants will exit the market, further reducing volumes of balancing requirements and reducing the pool of buyers and sellers. Whilst overall gas demand will be larger due to the demand of the LNG facilities, the number of participants managing marginal gas will be diminished. Note also that the market will be dominated by the LNG producers, each with control over vast amounts of gas that could materially move the gas price, making the gas market a more risky place for trade for smaller participants. This is explored further in the response to Question 6.

Compounding this, to date AEMO has not forecast a change in gas use in the residential or commercial sectors and is predicting it will grow as it has historically, broadly in line with population growth. It is clear that this is not an approach that recognises the growing push for fuel switching at the household and commercial level and the increasing impact of energy efficiency measures. It has been reported that:

AEMO have indicated that their next version of gas forecasts will acknowledge fuel-switching from gas to electricity in the residential sector. [3]

This is likely to further reduce AEMO's forecasts of gas demand and will in turn reduce the requirements of retailers and potentially their number.

In such an environment, it is difficult to envisage the development of a gas trading market in Eastern Australia that will play a material role in contributing to the primary gas market. APGA considers a vision that acknowledges this is essential to effective future market development.

Nevertheless, enhancements can be made to trading markets to improve the efficient allocation of secondary gas. If circumstances change, as gas market participants are well aware they can, an enhanced gas market that efficiently allocates marginal gas will be well placed to further develop.

[3] UoMEU Switching off gas, p7

4. How many and what type of wholesale gas trading markets are required to meet the Energy Council's Vision and how should this be assessed?

Gas supply hubs and balancing markets both have a role to play in improving market liquidity. The current location of these, at centres of supply and demand respectively, is appropriate and delivers the greatest prospect of enhancing liquidity.

Supported by increased capacity trading, there is every reason to believe the appropriate application of these types of markets can achieve the Energy Council's vision to the extent it is possible to do so within the Australian market structure.

There is no 'magic number' of trading hubs that is suitable for the Eastern Australian Gas Market. The number of trading markets required to meet the Energy Council's vision should be determined through consideration of the appropriate types of trading hubs and subsequent analysis of suitable locations for trading hubs.

For any trading market, due to determine the suitability of its implementation, there are questions regarding its fundamental characteristics that must be considered during conceptualisation. These characteristics are considered below.

Voluntary trading markets vs Compulsory trading markets

In Australia's relatively small gas markets, it can be tempting to consider that compulsory markets are needed in order to generate sufficient volumes and participants to drive liquidity. However, the liquidity that is present in compulsory trading markets tends to be a false liquidity, with the majority of participants behaving in a manner to minimise or remove exposure to the market pricing.

Allocation of costs

Importantly, compulsory markets decouple costs from services and inefficiently apply the costs associated with the market to all participants. This means those participants not using the market services will subsidise those that are. This tends to lead to a 'freeloader' situation where a small number of active participants receive the greatest benefit from the compulsory market whilst only paying a partial contribution to its cost.

True costs of transaction

It also hides the true cost of compulsory markets. APGA has previously provided information to the Commission's Stage 1 Review Process on the costs of the STTMs and the DWGM on a gas traded basis.

Facilitated markets are often advocated as a means of reducing transaction costs. When compulsory markets are imposed, they socialise the costs across all participants, including those that would otherwise not participate in the market. This provides the illusion of reduced transaction costs. The fact of costs becomes clear when the costs of a compulsory market are compared to the volumes traded.

Potential to impact existing arrangements
Depending on the extent of a compulsory market, it can also impact on existing contractual arrangements and rights. When concepts led to this circumstance, additional costs of compensation to affected parties must be considered. Such costs can be managed, but they materially reduce the likelihood that a compulsory market can deliver net benefits.

Voluntary hubs should feature in the preferred concept
The implementation of the Wallumbilla Gas Supply Hub demonstrates that voluntary hubs can be developed and implemented in a manner that improves liquidity and appropriately attributes the costs of establishing and running a market to those that are utilising the services of the market.

APGA considers that voluntary trading markets are preferable to compulsory trading markets in all circumstances.

Physical hubs vs Virtual hubs
Similar to compulsory markets, Australia's relatively small gas markets can lead to an assumption that virtual hubs are necessary to aggregate sufficient volumes and number of participants to generate genuine liquidity. There are a number of factors that must be considered when conceptualising virtual hubs.

Assumptions regarding physical circumstances of virtual hubs
The first is the physical circumstances of any virtual hub. In gas markets, virtual hubs require assumptions that:

- gas can enter the system at any point and leave at any point;
- gas is evenly distributed throughout the system; and
- gas can instantaneously travel throughout the system.

None of these is true, and creating a system that substantially overcomes physical constraints is likely to require significant investment that outweighs the benefits of such markets.

The challenges presented to virtual hubs in managing the disconnect between the assumptions that must be made to implement them and the physical reality are demonstrated through the issues in the DWGM regarding ancillary payments, in particular those that would arise where there is a separation between the operating and pricing schedules. These separations can be a sign of constraints within the system, but as signals for investment they are indirect and imperfect.

The development of physical hubs also tends to encounter difficulties between assumptions required to manage the trading market and physical realities. The STTM in Adelaide had ongoing issues with counteracting MOS for many years. In Sydney, the differences between the Wollongong facilities and the Sydney network created false requirements for balancing services that are yet to be fully resolved. In the Brisbane STTM, assumptions concerning the impact of backhaul services contributed to a false scarcity in that market. When such challenges exist in the implementation of physical hubs, they are highly likely to dominate the implementation of virtual hubs.

Potential for virtual hubs impact on existing arrangements

Virtual hubs have immense potential to impact on existing contractual arrangements and rights. In some circumstances, such as envisaged under Concept 3, virtual hubs would require widespread changes to the existing regulatory regime. Such changes could impact infrastructure investors, parties holding contractual rights to infrastructure and the shareholders of both. The costs associated with compensation for such changes are highly likely to dwarf any demonstrable benefits accruing from the implementation of Concept 3. APGA has noted the Productivity Commission's statements with regard to changing access arrangements and the costs of overriding private property rights in the Introduction to this submission.

Further, large virtual hubs typically have problems allocating firm transportation rights. In such an environment, investment is often delayed and this can materially impact market efficiency. The Commission is well aware of the issues the DWGM experiences in this regard.

Physical hubs can generate genuine liquidity

Physical hubs, located in line with current practice at supply and demand centres, have the potential to generate genuine liquidity at the locations it is most beneficial. They can do so with minimal material impact on existing regulatory and commercial frameworks as has been demonstrated through the implementation of three STTM hubs and the GSH. Such liquidity, providing the appropriate level of flexible support to primary gas supply arrangements, is desirable to begin the self-reinforcing loop required to enhance future liquidity.

International experience

It is apparent that the US approach has tended toward physical hubs and point-to-point transport arrangements. In contrast, the European approach has tended toward virtual hubs and entry-exit transport arrangements.

Each has a particular value and it must be acknowledged that both developed from very different starting points. From APGA's perspective, it appears the highly liquid US markets have evolved with relatively little regulatory intervention, particularly in the last 20 years, whilst the European approach seems to undergo frequent major reform and imposes heavy-handed regulation on the transmission sector.

5. Does having multiple gas hubs contribute to or detract from the objective of achieving a liquid wholesale gas market and why?

APGA considers detailed comparisons between international gas markets and the Australian gas market are of little value, a view shared by the Productivity Commission:

Importantly, the effect of such provisions in other countries is unlikely to provide clear policy guidance in Australia. Australia's gas markets fundamentally differ from gas markets in the United States and Europe, which are more developed, more liquid and have many more buyers and sellers.[4]

Despite this, an observer must only look to the gas markets of Europe and North America to reach a conclusion that multiple hubs are compatible with a more liquid wholesale gas market.

6. What are the main barriers to achieving a liquid wholesale gas market on the east coast and are regulatory solutions required?

There are a number of barriers to achieving a liquid wholesale gas market

Market Structure

The market structure of the Eastern Australian gas market is such that it is the primary barrier to achieving a liquid wholesale gas market.

Number of participants

The Commission has documented the number of registered participants in each market in Australia, but has not articulated the number of unique participants. Not only is there a

[4] PC, Examining Barriers to More Efficient Gas Markets, p120, March 2015

relatively low number of unique participants, most of them are active in a subset of the East Coast gas market. Very few are active in more than two markets.

Even in the DWGM, with the most unique participants at 52, liquidity is forced and for almost all users is a supplement to primary gas supply rather than a source of primary gas supply. It appears to provide no extra benefit to Victorian gas users compared to other East Coast gas users in the current environment.

The exception is new entrant retailers. It is undeniable that the DWGM has made it easier for sophisticated parties to establish new retail entities and enter the Victorian market. Such retailers can deliver savings to household and commercial consumers; however APGA understands that these new entrants are not necessarily relying on the market to secure their gas needs. Many also have bilateral agreements with producers and are trading through the DWGM. APGA notes that almost all of these new entrants have been acquired by a larger retailer once they have an established customer base.

Size of participants

Information of the production capability of each producer and the gas demand of each user is not readily available. This limits the ability of market observers and policy makers to conduct detailed analysis on the size of participants in the Eastern Australian gas market. However, there is quality data available on reserves holdings, and high-level analysis suggests the concentration of reserves among LNG proponents is a challenge to the development of a liquid wholesale market

Considering the East Coast as a whole, the companies participating in the three LNG export projects control 65.8% of East Coast gas reserves. EnergyQuest data[5] indicates the APLNG project partners hold 29.9%, the GLNG partners hold 16.8% and the QGC partners hold 18.9%. The fourth project, Arrow, controls a further 19.1% of reserves and there is a reasonable likelihood this will be allocated to existing projects. The Bass Strait Joint Venture controls 6.1% of reserves and AGL holds a further 3.7%. The remaining 5.5% of reserves is held by a number of small companies.

Application of the Herfindal-Hirschmann Index (HHI) to these reserves holdings produces a result of 1988.36. This is well outside the range of a competitive market, which should deliver a result less than 1000.

[5] EnergyQuarterly August 2015. APGA notes that EnergyQuest reports the reserves holdings and production capability of each partner. APGA has aggregated these numbers as the partners do no individually market gas to domestic consumers.

APGA considers this result, already very high, is likely to underestimate the actual level of market concentration that the Eastern Australian gas market will experience in the future. It seems very unlikely the fourth LNG project will go ahead. A more likely scenario is that its reserves are purchased by the other LNG project partners. The proposed Shell takeover of BG is a further factor that would contribute to a much higher HHI result,

In terms of current production levels, HHI analysis is equally concerning. EnergyQuest data indicates that the partners of the three LNG projects and the Bass Strait Joint Venture accounted for 86.7% of East Coast production in the 12 months to June 2015. These companies alone produce a HHI result of 2032.5.

Again, this result is likely to underestimate the actual level of market concentration in production that will exist when all three LNG facilities are operating at full capacity, Further, as the activity of the three LNG facilities is concentrated in Queensland, all hubs developed and implemented in Queensland will be even further concentrated, as the slightly mitigating activity of production outside Queensland would not be included in any Queensland specific HHI analysis.

As a final observation, APGA notes that the three LNG facilities are also active participants in the demand side of the market, where they account for approximately 70% of East Coast demand. APGA does not fully understand how this will affect any HHI analysis but considers it must be a further indicator of such market concentration that is likely to be a barrier to the establishment of a liquid, wholesale gas market.

Regulatory solutions

It is very difficult to see how a market development solution can address the market structure issues in the Australian market. It would require an extreme regulatory solution to restructure the production sector to address issues of market concentration. Even if such a solution was pursued, regulation can only increase the number of gas users in Eastern Australia by mandating its use. Again, this is an extreme application of regulation.

Surplus gas from unexpected LNG shutdowns is not sufficient to underpin a spot market

As the Commission sets out in section 3.1.1, unexpected LNG shutdowns have the potential to supply large volumes of gas to the market at short notice. It is of benefit to all market participants if these volumes are allocated efficiently. However, these volumes, made available infrequently, are insufficient to provide ongoing, reliable liquidity to the market.
It is already apparent that agreements are in place between LNG exporters to enable them to allocate surplus gas amongst themselves during periods of planned shutdown. APGA

notes that the major pipelines transporting gas to Gladstone have built interconnections to achieve this goal. This has been reported publically.

"The interconnect points will enable gas to flow from one project to the other when necessary, for example to allow for LNG plant downtime and planned maintenance to occur without interrupting either project's gasfield operations,"[6]

If these agreements also cover the allocation of gas in the case of unexpected shutdowns, then the frequency and size of these sporadic events may be further limited.

In any event, whilst it is important that market structures are in place to manage such occasions, those occasions do not drive a genuine liquidity that can be utilised by market participants to supplement primary supply arrangements. These extreme events are also likely to see significant price movements that may undermine liquidity and the formation of a trusted forward price.

A lack of pipeline investment is a barrier to liquid markets

The most effective way that transportation arrangements can improve liquidity is through the addition of new capacity. As discussed by the AEMC in its stage 1 report, there has been significant investment in new pipeline capacity in recent years. This is an area of success for the market.

New market arrangements (and any associated arrangements for pipeline capacity trading) need to maintain those investment settings to support the future growth of the market. As noted by the AEMC in respect of the DWGM, virtual markets do not support timely and efficient investment.

Further, the task before the AEMC requires it to take a long-term outlook. Dynamic change appears to be the new norm, as least for the foreseeable period, and there needs to be an ability for the market, infrastructure, and regulatory settings to respond to that change. Rigid settings, as typically introduced through regulatory mechanisms, will reduce liquidity as they are unlikely to support the diversity of potential new markets and market participants, as well as the services that those markets or market participants seek. Further, it should not be assumed that current pipeline utilisation rates will continue into the future, or that pipeline flows (or even direction) are settled within the market. The need for further investment remains and this must be supported under any future regulatory model.

[6] Rod Duke, Santos Vice-president GLNG Downstream, quoted in the Australian newspaper on 5 July 2013.

As the PC has noted:
Further development of the eastern Australian gas market would require investment in gas transmission pipelines. Timely investments in gas transmission pipelines can help to relieve physical gas supply constraints and put downward pressure on prices.[7]

The PC modelled the costs of regulatory delay to pipeline investment and found:
Model results indicate that if investments are delayed, supply is constrained and gas prices increase in areas directly affected by transmission constraints. In particular, gas users in Brisbane are subject to transmission constraints, leading to an increase in prices that abates after new transmission capacity becomes available (figure 6.1). For the most part, prices do not increase in other demand centres because in the modelled future scenario these areas are not subject to pipeline constraints. Delays to pipeline investments also increase the volatility of wholesale gas prices relative to the baseline under all three LNG price scenarios.[8]

7. Could the virtual gas hub design concepts set out in section 8 be feasibly implemented on the east coast of Australia? If not, what barriers exist?

APGA has set out the reasons it considers virtual hubs are not the best approach for gas market development. In particular, Concept 3 is not feasible. The regulatory changes required would be highly interventionist and interfere with existing property rights to the extent that the costs associated with implementation are simply too high.

Concept 2 also involves changes to the regulatory regime and structure that do not appear to address the underlying issues in the market. Creation of virtual hubs will not address existing pipeline constraints (bearing in mind that utilisation rates on the South West Queensland Pipeline and at the Wallumbilla Hub are expected to increase significantly by the end of the year), and will undermine incentives to invest. There are also long-term contracts in place for a variety of services at Wallumbilla and on the Roma Brisbane Pipeline which would be unlikely to fit within a virtual hub structure.

As the PC has found:
However, it is clear that access regulation can affect investment incentives. If pipeline owners are uncertain about how regulation would be applied (as discussed above) and if there are risks associated with the arrangements for determining regulated prices to expansions, the risks from investing in pipeline infrastructure could be compounded. These risks could increase investors' hurdle rate of return for making investments in spare

[7] PC, Examining Barriers to More Efficient Gas Markets, p105, March 2015
[8] PC, Examining Barriers to More Efficient Gas Markets, p109, March 2015

capacity beyond the expected return, inhibiting investment. Also, if regulated rates of return are not expected to fully compensate investors for the risks incurred, investments may not proceed. Given that regulators are unable to set optimal access prices (prices that would maximise overall economic efficiency) with precision, there is also scope for regulatory error in the setting of access terms and conditions.[9]

8. Do existing contractual rights and/or issues around cross border trade preclude any particular gas hub designs?

APGA considers that existing contractual rights will be least disrupted if a concept aligned with concept 1 is pursued. It is inevitable that virtual hubs will impact contractual rights and this will add significant cost to their implementation, likely to the point where they are unable to deliver net benefit to the market.

9. Are different gas specifications, such as a higher quality specification for the LNG plants and the odourisation of some transmission pipelines, likely to act as a barrier to trade in the future?

Both lean gas and the standard gas specification meet the requirements of AS 4654. Pipeline transport agreements largely allow for any gas that meets AS 4654 to be injected into the pipeline. New agreements are consistent with AS 4654. As such, both gas specifications are able to enter transmission pipelines across the East Coast. The exception to this may be the new major pipelines transporting gas from the Bowen-Surat Basin to the LNG Facilities at Gladstone. Pipeline operators work with market participants in this regard and do not seek compensation for the fact that the lower energy density of lean gas has an impact on the total capacity of a pipeline.

Despite this, the differing gas specifications may act as a barrier to trade. Participants with export exposure may refuse to purchase standard specification gas. There is the potential they will insist on further processing. Interestingly, APGA notes that further processing of gas would be a service that could not meet the production process exemption for coverage under the National Access Regime, opening the door to appropriate oversight of gas processing facilities.

[9] PC, Examining Barriers to More Efficient Gas Markets, p115, March 2015

Conclusion – APGA supports a version of concept 1

Imposing artificial and compulsory constructs over geographically dispersed physical infrastructure is an undertaking that is fraught with complexity and should not be undertaken without certain net benefit.

In an environment where the fundamental market structure is its own barrier to liquidity (addressed in the response to question 6), it seems appropriate to pursue an approach that could be delivered with minimal regulatory intervention and which reflect the known and expected growing scope of gas market trading marginal gas. This is in line with all of the high-level principles set out by the Commission in Appendix A.3.2.

APGA considers that a series of physical, voluntary hubs could be developed to enhance liquidity in the existing market without significant changes to the current regulatory settings. A version of concept 1, with supply hubs at Wallumbilla, Moomba and in Victoria and supported by voluntary balancing markets in Victoria, Sydney, Adelaide and Brisbane, could support increased liquidity of marginal gas at these central locations which could develop into a secondary market that:

- provides enhanced risk management options through increased liquidity of marginal gas;
- minimises regulatory intervention; and
- provides the foundation for a self-reinforcing loop of genuine liquidity to emerge.

APGA agrees that the balancing arrangements in each market need to be common, however the balancing period needs to reflect the characteristics of the market (as discussed in section 7.1.1 of the paper) . The current practice of intraday balancing in Victoria and once-a-day in other balancing markets serves a purpose for each market. In particular, intraday balancing meets the specific requirements of the Victorian market. The DWGM experiences high peak day demand, well in excess of the linepack of the VTS, leading to a utility of intraday balancing for that market that is not reflected in other balancing hubs.

APGA does not consider balancing markets at Gladstone or the ACT are required. These locations are proximate to other hubs and services can be developed to provide access to hub services at these locations. Similarly, a single physical supply hub in Victoria is appropriate.

Such an option does require enhancements to transportation arrangements. A more liquid secondary market for pipeline capacity would need to emerge. The framework for this has been put in place on pipelines around Wallumbilla and could be expanded.. Some form of enhanced firm transportation rights would be required in Victoria to implement a Victorian supply hub.

Implementing the required arrangements for concept 1 in Victoria will be challenging. As concept 2 does not require any changes to the existing arrangements in Victoria, APGA considers it actually embodies a concept that is closer to the status quo than that proposed by concept 1.