REVIEW

Australian Energy Market Commission

STAGE 2 FINAL REPORT

East Coast Wholesale Gas Markets and Pipeline Frameworks Review

23 May 2016

Reference: GPR0003
Stage 2 Final Report

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Reference: GPR0003

Citation

AEMC 2016, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Stage 2 Final Report, 23 May 2016, Sydney.

About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive Summary

The gas industry on the east coast of Australia is undergoing a structural change. Largely isolated point-to-point pipelines have evolved into an interconnected network, supporting a series of increasingly interlinked markets. This transformation has been accelerated by the Queensland-based liquefied natural gas (LNG) export industry driving an increase in demand from 694 petajoules (PJ) in 2014 to an expected 1,961 PJ in 2020, with consequential impacts on the level and variability of gas flows and wholesale prices.[1]

Historically, natural gas on the east coast has been traded through long-term bilateral gas supply agreements (GSAs). These contracts have traditionally covered periods of 15 to 20 years in order to underwrite investments in capital intensive, long-lived assets. In this relatively stable environment, the role of gas trading markets was mostly to manage daily imbalances in a transparent and competitive manner.

The substantial increase in demand driven by LNG exports has put upward pressure on domestic gas prices. The LNG industry has also presented a new risk in the form of prices in GSAs being linked to oil and increased spot price volatility. Coinciding with this transformation is the expiration of many long-term GSAs, with domestic users having to negotiate new contracts in a vastly different market. GSAs are typically now being offered at higher prices, for shorter durations and with more restrictions on volume flexibility.[2]

While bilateral contracts will remain a fixture of the east coast market, more flexible and sophisticated means of managing gas portfolios are becoming increasingly important to participants. Greater flexibility in how gas is bought and sold outside of GSAs and new approaches to managing spot price volatility risk will be required. The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed and it is these factors that have led to a renewed focus on market development to promote efficient outcomes for consumers.

The Energy Council's Vision for Australia's future gas market

Recognising these changes, the Council of Australian Governments Energy Council established a set of principles, referred to as the Energy Council's Vision ("the Vision"), for Australia's future gas market.[3] A key outcome of the Vision is the establishment of an efficient and transparent reference price for gas. A transparent reference price allows gas consumers to know whether the price they are being asked to pay reflects underlying supply and demand conditions. This requires a liquid market with many parties buying and selling gas. This necessarily implies that trade be focused at a point that best serves the needs of participants - another aspect of the Vision.

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1 AEMO, *National Gas Forecasting Report*, Forecasting Dynamic Interface, accessed May 2016.

2 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 18.

3 The Vision is set out in Chapter 1.

A liquid trading market is a means to promoting greater *efficiency* in the supply of natural gas. It is not an end in itself. An efficient market supports outcomes where gas is supplied to those consumers who value it the highest, at the lowest possible cost, over time. A liquid trading market facilitates the buying and selling of gas on an equal basis to other players, and the hedging of price risk, which lowers barriers to entry and promotes competition. Trading gas through well-functioning markets is fundamental to consumers not only knowing whether the gas price reflects underlying demand and supply, but also forming expectations of future price movements.

A liquid trading market exists when no single transaction is likely to move the price excessively; individual trades can be easily executed; there is an ability to trade large volumes in a short period of time; and the market can recover towards its natural equilibrium after being exposed to a shock. Importantly, liquidity is not in itself about increasing the volume of gas supplied to the market, though it can facilitate this outcome. It is about increasing the *traded* volume of gas in the market - the number of times gas is bought and sold between different entities before being consumed.

Growth in trading liquidity requires the creation of a self-reinforcing cycle that encourages both the demand and supply side of the market to participate. More participants and greater traded volumes lead to more meaningful pricing signals, giving sellers confidence they will have a market for their supply. Liquidity also gives buyers the confidence to supplement their bilateral contracts with gas from a trading market. As trading volumes increase, financial risk management tools will be developed by industry, reducing the cost of managing price risk and encouraging even more participation in the physical market.

Developing a roadmap to meet the Vision

In order to identify a roadmap for achieving the Vision, the Energy Council requested the Australian Energy Market Commission ("AEMC" or "Commission") review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia ("the East Coast Review").[4] Concurrently, the Energy Council, at the request of the Victorian Government, asked the AEMC to undertake a detailed review of the Victorian Declared Wholesale Gas Market ("the DWGM Review").[5] The Draft Final Report for the DWGM Review will be published in October 2016 after the Commission has undertaken further detailed market design and consultation with industry.[6]

In parallel with these reviews, the ACCC was tasked with reviewing competition in the east coast gas market. Consistent with the Commission's findings, the ACCC found that short-term trading options are becoming increasingly important to users. Greater liquidity in wholesale gas markets would improve price discovery and help market participants manage volume fluctuations, while facilitating new entry by retailers in

4 See Appendix A.

5 See Appendix A.

6 Victorian Government, *Response to the Draft Review of the Victorian Declared Wholesale Market*, 13 May 2016, available at: http://www.aemc.gov.au

downstream gas markets.[7] In addition, the ACCC analysis found that access to pipeline transportation capacity at a reasonable price is also important for the development of this market.

Recommendations in this Stage 2 Final Report form a response to many of the recommendations made by the ACCC. A number of the ACCC's remaining recommendations relate to issues outside of the Commission's remit, such as moratoria on gas exploration and development. A summary of how the AEMC's recommendations address matters raised by the ACCC is set out in Table 3.

The Commission's recommended roadmap for market development

The East Coast Review has been structured over two stages. In July 2015, the Commission published the Stage 1 Final Report, which included a gap analysis between the current market arrangements and Vision, as well as recommendations that could be progressed in the short term.[8] Stage 2 has more fully developed medium and long-term adjustments required to achieve the Vision, including the transition path.

In this Stage 2 Final Report, the Commission has recommended a gas market development roadmap that brings together recommendations on wholesale and transportation capacity markets, and information provision. As shown in Figure 1, the recommendations are interlinked and represent a balanced and proportionate suite of reforms designed to promote the Vision and the National Gas Objective.

Promoting the efficiency of the gas supply chain through the development of a liquid wholesale gas market as set out in this report will result in a tangible gain in wealth for the Australian economy. PwC estimates that achieving the Energy Council’s Vision by implementing the integrated package of reform developed by the Commission has the potential to result in an annual increase in Australia’s Gross Domestic Product of between **$500 million** and **$3.3 billion** by 2040 even after implementation costs have been considered.[9]

Further detail on each aspect of the reform package is set out below, while a summary of the Commission’s recommendations is provided at the end of this section in Table 1.

7 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 14.

8 Appendix D provides details of the current progress of the implementation of the Stage 1 recommendations.

9 Further discussion on the estimated benefits and costs of the proposed gas market development roadmap are discussed in Chapter 2 and PwC’s report published on the AEMC's website.

Figure 1 An integrated gas market reform package

Wholesale gas trading markets

The Commission is recommending a pathway for the future development of wholesale gas markets that seeks to concentrate trading at two points on the east coast – in the north by continuing to evolve the existing Wallumbilla Gas Supply Hub (GSH) and in the south by enhancing the Victorian DWGM.

Two primary pricing points have been recommended as the Commission is concerned that multiple trading locations unnecessarily split liquidity and reduce the benefits to participants of a liquid wholesale market. Prices at the two hubs would seek to reflect the differing market conditions in the two regions which both have significant sources of supply and demand:

- In Queensland, demand is primarily driven by LNG production and large users (including gas-fired generation) and there is conventional and unconventional gas production.

- In Victoria, gas is primarily consumed by residential customers, and so is driven by day-to-day weather and the seasons. There is also offshore production, which is increasingly important for domestic demand across the east coast.

The Commission recommends that price discovery at both markets occurs via continuous exchange-based trading, consistent with the design of the GSH, and with common gas day start times, back-end systems, registration, prudentials, settlement and training where possible. This should lower transaction costs and complexity for businesses operating across multiple markets, encouraging greater participation.

The multiple market designs currently in place create complexity, costs and inefficiencies which discourage greater participation. Some participants are currently only registered at the hubs where they directly consume gas, which limits their ability to trade across the east coast. A fully integrated east coast gas market will provide all suppliers and users of gas with an opportunity to easily participate at any of the hubs in order to realise commercial benefits.

The wholesale gas market recommendations are set out in Chapter 4 and summarised as follows:

- Focus development efforts on two primary trading hubs - a Northern and Southern hub - that share common trading arrangements to improve price discovery and reduce barriers to participation.
- The Northern Hub to be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of Optional Hub Services.
- The Southern Hub to be transitioned from the existing DWGM design to continuous exchange-based trading, supported by a system of firm capacity rights.
- Simplification of the Short Term Trading Market (STTM) hubs to balancing mechanisms following the development of the Northern and Southern hubs, and pipeline capacity trading.

Consolidating the various existing market designs effectively into a single set of trading rules allows participants to trade the same type of product in either the northern or southern hub. This will allow for the efficient movement of gas across the east coast in response to changing price signals in those markets. The 'clean' wholesale price that will emerge from an exchange will allow for the development of an effective reference price to support the creation of financial risk management tools.

Continued development of the Wallumbilla GSH to provide a Northern Hub

Wholesale commodity trading is already undertaken at Wallumbilla through the GSH, which was introduced in March 2014. Liquid trading is most likely to develop where there is a diversity of producers and users, and potentially other services that facilitate trading (such as storage). The Commission considers that Wallumbilla, which is located at the intersection of numerous pipelines connecting a range of producers, users and other facilities (including storage), represents the most appropriate location around which to base a northern trading hub.

Trading at Wallumbilla has been hampered to date by physical constraints within the infrastructure there, which means that gas cannot always flow completely freely, and which has required that trade be split across three points. The Australian Energy Market Operator (AEMO) has been undertaking a work program to progress this issue and is in the process of implementing the "Optional Hub Services" model.

The Optional Hub Services model reduces the three pricing points at Wallumbilla to one, thereby pooling liquidity and potentially creating more trading opportunities. It will also include implementation of hub services products that will allow participants to trade compression capacity at the hub. The Commission understands that implementation of a single Wallumbilla pricing point should occur by March 2017.

Creation of a single Wallumbilla pricing point concentrates trading liquidity, but also increases the compatibility of the market with the proposed Southern Hub design - contributing to the development of a single east coast gas market. As discussed below, the Commission recommends that continuous exchange-based trading replace the current DWGM gross pool design. Exchange-based trading at the Northern and Southern hubs supports the efficient allocation of gas by allowing participants to arbitrage prices between the hubs through trading fungible products.

After the implementation of the Optional Hub Services model the Commission would recommend to the Energy Council that additional work to expand the geographic scope of the Wallumbilla GSH be considered and progressed through the Gas Reform Group (discussed further below). The Commission's recommendation to expand the Northern Hub would be informed by its biennial review of liquidity in the wholesale gas and pipeline capacity trading markets, as discussed below and in section 3.2.

Reforming the existing DWGM arrangements to develop a Southern Hub

The Commission recommends the DWGM transition to continuous exchange-based trading, underpinned by a market-based balancing mechanism. A key feature would be the introduction of an exchange similar to that at Wallumbilla, providing a low cost, anonymous and transparent way for participants to trade. While this would alter the means of exchange – the financial transactions between buyers and sellers – it would not necessitate changes to the way in which gas physically flows across the system.

To support this new form of trading, the Commission also recommends that the market carriage model is replaced with a system of firm rights for capacity allocation. This would allow network users to book firm transportation capacity rights independently at each entry and exit point to the Victorian Declared Transmission System.

On 13 May 2016, the Victorian Government extended the period of time within which the AEMC must undertake its Review of the Victorian Declared Wholesale Gas Market. The reason for the extension is to allow the AEMC to undertake additional consultation with stakeholders and further analysis. This additional work is to be undertaken and the review completed by October 2016.[10]

The Victorian Government notes that there is likely to be benefit in implementing the Commission's recommendations for the voluntary continuous exchange-based trading of gas and the establishment of a system of entry and exit rights for firm access to pipeline capacity. However, the Victorian Government has requested further detailed design work be carried out so that it is in a position to better assess the recommendations.

Further detail on how the Commission intends to progress this work is in section 4.3.4.

Evolution of the Short Term Trading Market hubs and Moomba GSH

In conjunction with the recommendations relating to the Northern and Southern hub and to pipeline capacity trading (see below), the Commission recommends the STTM hubs be simplified from their current design to purely support the trading of daily imbalances. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still providing a transparent and competitive balancing arrangement.

Similar to the Wallumbilla GSH, the Commission proposes to advise the Energy Council on the appropriate time to simplify the STTM hubs through its biennial review of trading liquidity in the wholesale gas and pipeline capacity trading markets, and for the development of those reforms to then be progressed by the GRG.

AEMO expects to have implemented an additional GSH at Moomba by 1 June 2016. While not explicitly part of the Northern Hub, a Moomba GSH is likely to be an appropriate transitional measure to provide trading flexibility until the Northern and Southern hubs, and capacity trading, mature. Over time, Moomba could establish itself as a transit point for gas flowing between hubs, particularly when the Northern Gas Pipeline is built connecting Tennant Creek in the Northern Territory to Mt Isa in Queensland.

Improvements to the pipeline capacity frameworks

Until recently, market fundamentals were more predictable and long-term contracts were relatively effective in allocating gas and transportation capacity. However, with the changes currently underway in the market, allocating gas to those that value it most is becoming more challenging and increasingly linked to the efficiency with which transportation capacity is allocated between shippers and used, particularly on contractually congested assets.[11] The ability to trade transportation capacity between shippers is therefore becoming increasingly important in the east coast market and will

10 Victorian Government, *Response to the Draft Review of the Victorian Declared Wholesale Market*, 13 May 2016, available at: http://www.aemc.gov.au

11 Contractual congestion occurs when a shipper is unable to gain access to an asset, despite it having physical capacity, because another shipper owns the rights to that capacity and is unable or unwilling to sell that capacity.

be critical to the success of the development of a liquid wholesale gas market and efficient reference price in the east coast.

The Commission considers that the current contract carriage model of pipeline access can be improved so that market participants are able to obtain more flexible and competitive pipeline capacity between hubs. The Commission's recommendations for the development of a liquid market for the secondary trade of pipeline capacity are set out in Chapter 5 and summarised as follows:

- Introduce a day-ahead auction of contracted but un-nominated pipeline capacity to be conducted shortly after nomination cut-off.
- Standardise provisions in capacity agreements to make capacity more fungible and allow shippers greater receipt and delivery point flexibility.
- Develop capacity trading platform(s) to facilitate sales by capacity holders ahead of the auction and provide for exchange based trading.
- Require the publication of information on secondary trades of pipeline capacity and hub services.

These recommendations directly address problems identified by the ACCC Inquiry. The ACCC identified that the short term trading of gas is currently restricted as frameworks are not in place to procure pipeline capacity at short notice in response to price signals at the hubs.[12] Introducing the recommendations above will lower barriers to trading gas on a short term basis, allowing more participants to enter the market and providing them with greater opportunities to manage risks through adjusting portfolio positions.

As discussed in Chapter 5, together the Commission expects these initiatives to facilitate more secondary capacity trading by using market based processes to allocate capacity on a non-discriminatory basis to those that value it most highly, reducing the search and transaction costs associated with secondary trades, reducing information asymmetries, which will aid the price discovery process, and improving the incentive shippers have to trade capacity.

In turn, improvements to capacity markets should improve the liquidity of trading at hubs, the reliability of hub prices, and in turn provide better signals for pipeline investment, and gas consumption and production – and hence promote the NGO. In particular, these recommendations seek to promote much shorter-term trades in pipeline capacity trading, which should support the ability of markets to generate prices that better reflect short-term shifts in supply and demand.

The ACCC Inquiry also identified issues with the pipeline access arrangements and identified a range of suggested changes, most of which are consistent with the Commission's recommendations in this area. In addition the ACCC recommended the Energy Council consider changes to the Gas Access Regime. Implementation of the

12 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 15-16, 152.

Commission’s recommendations to enhance secondary capacity trading could occur while the longer term process associated with changes to the Gas Access Regime was established.

Information to support the market

The Commission's recommended approach to the evolution of gas trading hubs and capacity markets on the east coast is supported by a detailed package of recommendations to enhance the information provided to the market.

An important characteristic of a workably competitive market is that participants have access to the information required to form expectations around movements in prices. In gas and capacity markets, such pricing expectations are not formed in relation to one specific data point, but require a range of information about production and consumption levels, transportation flows, and investment levels in both the short- and long-run.

A central repository of information for use by all market participants and the public exists in the form of the Natural Gas Services Bulletin Board. The Commission has developed a package of recommendations to improve information transparency, including expanding coverage of the Bulletin Board so that a wider range of information is provided and enhancing the reporting and compliance framework.

The Commission's recommendations for improvements to information provided to the market are summarised in Chapter 6. Specific details on the information recommendations, including proposed changes to the National Gas Law (NGL) and National Gas Rules (NGR), are set out in a supplementary report.[13]

Implementation of the Commission's gas market development package

For consumers to realise the benefits of a more efficient gas market, the process for implementing the roadmap map for gas market development should commence as soon as possible. Continuing the momentum of reform will require dedication of resources and coordinated effort between industry participants, government officials and the energy market institutions.

The need to progress the reforms in a timely manner is being driven by the pace of change in the east coast gas market. By the end of 2018, all six of the LNG export trains at Gladstone are expected to be fully operational, while one of these projects continues to source substantial volumes of gas from outside its portfolio, reducing supply that could have been directed to the domestic market.[14] Over the same period around 450

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13 AEMC, *East Coast Wholesale Markets and Pipelines Frameworks Review*, Stage 2 final report: information provision, July 2016.

14 On 24 December 2015, Santos announced to the ASX that GLNG had contracted with AGL to buy 254 PJ of gas over 11 years commencing in January 2017.

PJ of long term GSAs are rolling off, requiring domestic users to enter the market to secure new supply in an uncertain environment.[15]

While the Commission considers that many of its recommendations should be implemented as soon as possible, others will need to be implemented in sequence. In this way, the Commission envisages that the implementation of the complete package will occur over several phases, requiring commitment to progress development of the market over the next decade.

The Commission’s recommendations regarding implementation of the roadmap are set out in Chapter 3. In summary, the Commission recommends that the COAG Energy Council:

- establish, through an inter-governmental agreement, a dedicated Gas Reform Group (GRG) with a full-time project management office tasked with developing the package of changes to the NGL, NGR and any subordinate instruments to implement the Commission's recommended wholesale gas and pipeline capacity market reforms (Recommendations 1-8). The GRG should take into account any preferred and suggested design elements outlined by the Commission;
- progress an amendment to s74(1)(a) of the NGL to give the AEMC a rule making power with regard to the regulation of pipeline capacity trading arrangements;
- task the Commission with providing a biennial report on growth in liquidity in wholesale gas and pipeline capacity trading markets;
- make the necessary amendments to the NGL and Regulations to add new reporting entities to the Bulletin Board framework;
- propose to the Commission changes to the NGR that, among other things, establish a new reporting model and reporting standard, and a new registration framework for the Bulletin Board; and
- request that AEMO immediately progress the Commission's recommended Bulletin Board improvements that do not require changes to the NGL, Regulations or NGR.

A Gas Reform Group should be created to facilitate wholesale market and capacity trading reforms

Direct industry involvement is required to develop the details of reforms with regard to wholesale markets and capacity trading prior to the rule change process. This degree of engagement is required because the reforms are intended to facilitate more efficient commercial transactions of gas and transportation capacity between market participants and are relatively complex.

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15 Department of Industry, Innovation and Science, *Gas Market Report 2015*, p. 40.

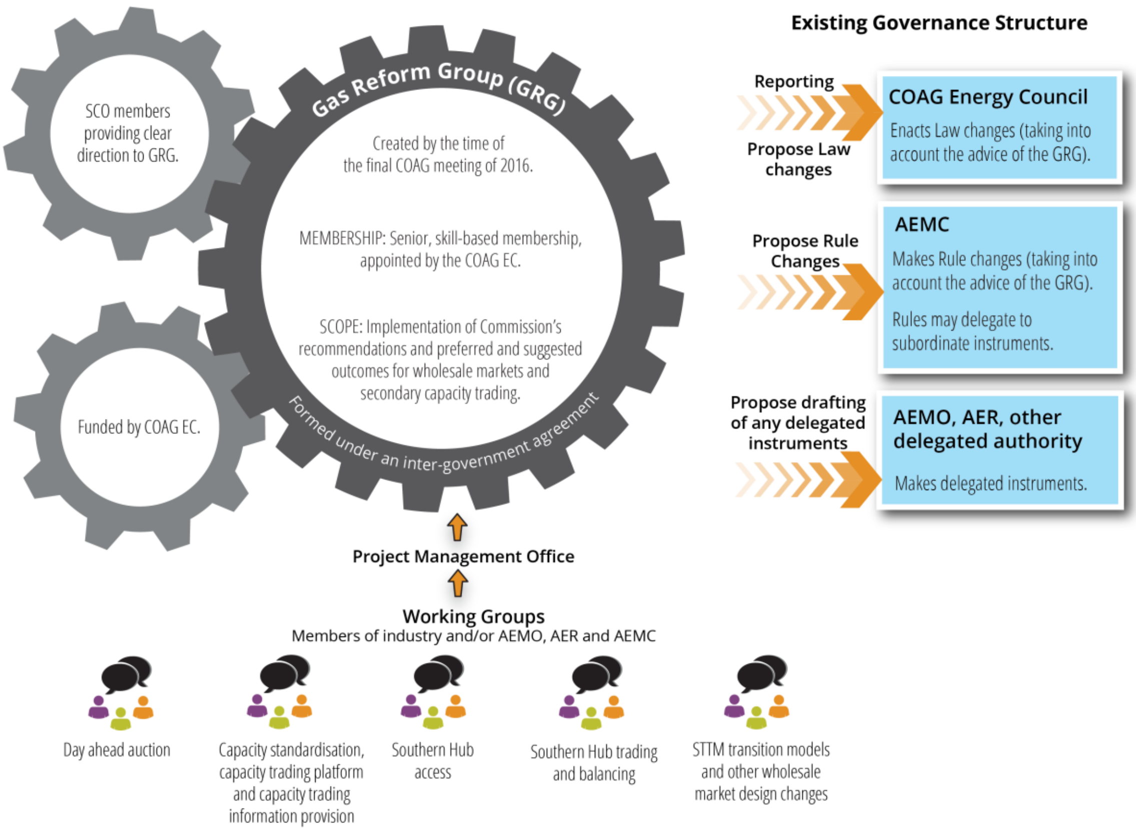
Nevertheless, a substantial degree of policy and regulatory involvement is required through the reform process to ensure that the private interests of industry do not supersede the long-term interests of consumers and that the detail of what gets implemented is consistent with the achievement of the Energy Council's Vision.

The Commission is therefore recommending that the COAG Energy Council creates a Gas Reform Group (GRG). The GRG should be tasked with developing and recommending the package of changes to the NGL, NGR and any subordinate instruments to implement the AEMC's recommended wholesale and capacity market reforms. The GRG should have a high proportion of senior industry and consumer group membership, providing a balance between industry involvement and policy and regulatory oversight.

The Commission has also highlighted **preferred** outcomes which the GRG should pursue unless it is clear that there are greater benefits in alternative approaches and **suggested** outcomes given the in-principle benefits that may arise from their implementation. These are detailed in Table 2 at the end of this summary.

A summary of the proposed GRG model is provided in Figure 2.

Figure 2 Summary of Gas Reform Group



Monitoring achievement of the Energy Council's Vision

An important element in determining whether the Energy Council's Vision is being achieved will be monitoring the development of liquidity in the wholesale gas and pipeline capacity trading markets. Monitoring market liquidity on an ongoing basis will allow policy makers, industry participants and the energy market institutions to understand how the gas and pipeline capacity trading markets are performing and the value they provide to gas market participants.

Accordingly, the Commission recommends that the Energy Council tasks it with reporting on a biennial basis on the growth in trading liquidity in the wholesale gas and pipeline capacity trading markets, with the first report provided to the Energy Council by July 2018. The Commission expects the first report to primarily cover how trading is developing at the Wallumbilla and Moomba GSHs, as well as updating Energy Ministers on how the market is adjusting to the structural changes underway.

Reforming the Gas Bulletin Board

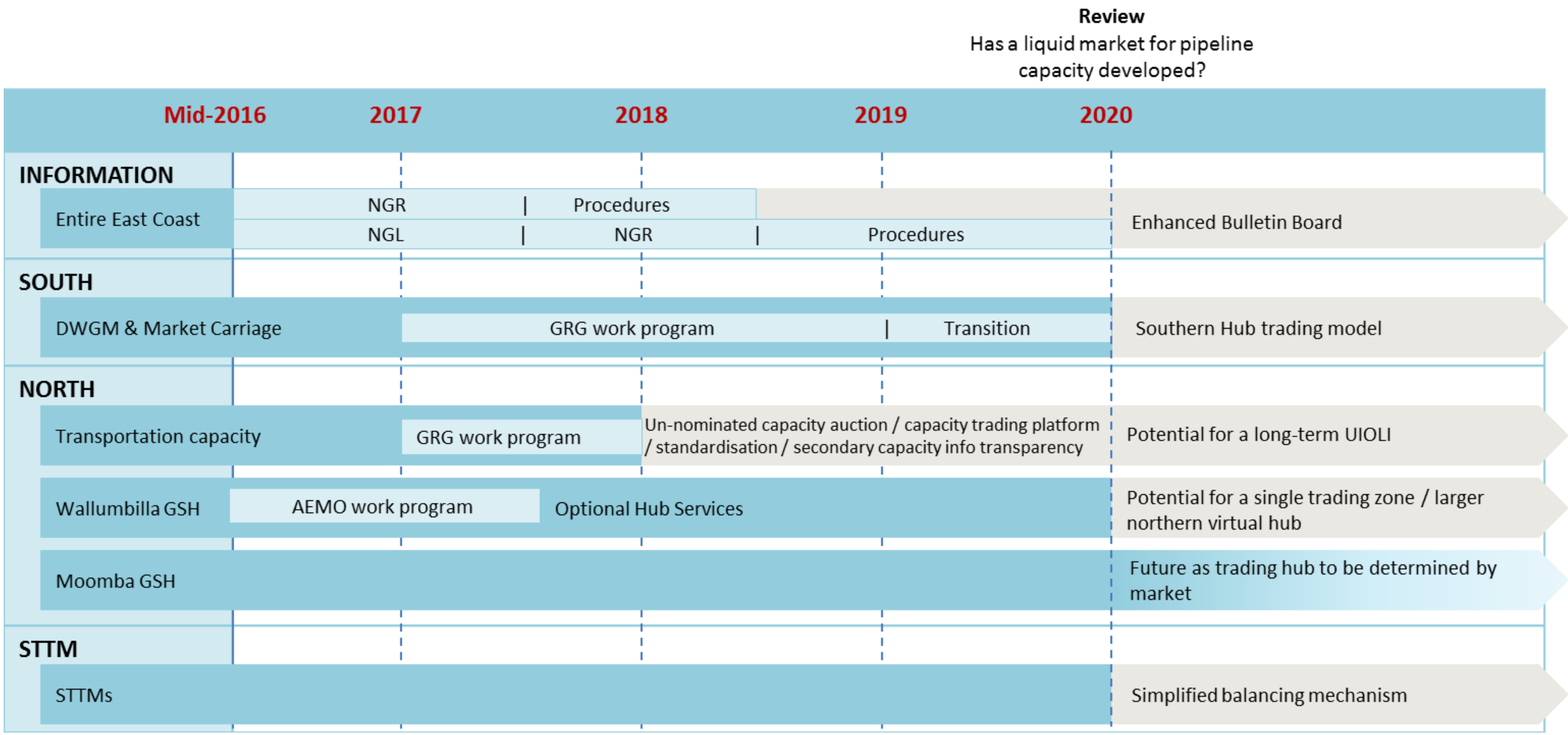
The Commission has made significant progress in analysing and consulting on the details of reform for the Gas Bulletin Board. Given this, and the relatively low level of complexity of these Gas Bulletin Board reforms compared to the wholesale and capacity market reforms, most of the reforms can be progressed as a next stage through amendments to the NGR. The Commission recommends that the COAG Energy Council submits rule change requests to the AEMC in these cases.

A number of the reforms require changes to the NGL and/or National Gas (SA) Regulations (Regulations) prior to rule changes being made, to add new reporting entities to the Bulletin Board framework. The Commission recommends that these changes are also pursued by the COAG Energy Council in parallel with the rule changes which can be progressed immediately.

In addition, the Commission has identified a small number of improvements to the Bulletin Board that can be made without changes to the NGL or NGR. The Commission recommends that the COAG Energy Council task AEMO with progressing these measures.

An overview of the staging of the overall package is set out in Figure 3 below, which also highlights certain dependencies later in the reform program.

Figure 3 Reforming east coast gas markets



The following tables summarise the Commission's recommendations for gas market development.

Table 1 Recommendations

Area	Recommendations
Wholesale markets	1. Focus development efforts on two primary trading hubs - a Northern and Southern hub - that share common trading arrangements to improve price discovery and reduce barriers to participation.
	2. The Northern Hub to be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of Optional Hub Services.
	3. The Southern Hub to be transitioned from the existing DWGM design to continuous exchange-based trading, supported by a system of firm capacity rights.
	4. Simplification of STTM hubs to balancing mechanisms following the development of the Northern and Southern hubs, and pipeline capacity trading.
Transportation capacity markets	5. Development and introduction of a daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services which happens shortly after nomination cut-off time. This auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in-kind, offer at least all contracted but un-nominated capacity, and accommodate nominations or renominations by incumbent shippers after the auction is conducted.
	6. Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services, which where possible and appropriate apply across the eastern Australian gas market. Standards to be developed are for key operational, prudential and other contractual provisions in GTAs[16], CTAs[17] and Operational GTAs[18], and provisions in contracts used for exchange based trading on the capacity trading platform. Counterparties to existing contracts should not be materially disadvantaged through the standardisation process.
	7. Creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms.[19] Trades carried out through the capacity trading platform to be given effect through an operational transfer. For other secondary capacity trades, bare transfers will be allowed but the seller will be required to offer the buyer the option to use an operational transfer.[20]
	8. Publication of information on all secondary trades of pipeline capacity and hub services. The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties, and should occur at or shortly after the time the transaction is entered into.
Information	9. Improvements should be made to the Natural Gas Services Bulletin Board to enhance the breadth and accuracy of information provided to the market, as detailed in recommendations A-K of the East Coast Wholesale Gas Market and Pipeline Frameworks Review Stage Final Report: Information Provision.

Area	Recommendations
Implementation and governance	10. COAG Energy Council to establish, through an inter-governmental agreement, a dedicated Gas Reform Group (GRG) with a full-time project management office tasked with developing the package of changes to the NGL, NGR and any subordinate instruments to implement the Commission's recommended wholesale gas and pipeline capacity market reforms (Recommendations 1-8). The GRG should take into account any preferred and suggested design elements outlined by the Commission.
	11. COAG Energy Council to progress an amendment to s74(1)(a) of the NGL to give the AEMC a rule making power with regard to the regulation of pipeline capacity trading arrangements.
	12. COAG Energy Council to task the Commission with providing a biennial report on growth in liquidity in wholesale gas and pipeline capacity trading markets, with the first report due by July 2018.
	13. COAG Energy Council to make the necessary amendments to the NGL and Regulations to add new reporting entities to the Bulletin Board framework.
	14. COAG Energy Council to propose to the Commission changes to the NGR that, among other things, establish a new reporting model and reporting standard, and a new registration framework for the Bulletin Board.
	15. COAG Energy Council to request that AEMO immediately progress the Commission's recommended Bulletin Board improvements that do not require changes to the NGL, Regulations or NGR.

16 Gas Transportation Agreements (GTAs) are entered into between a pipeline owner and a shipper for the sale of primary capacity.

17 Capacity transportation agreements (CTAs) are entered into between shippers when trading secondary capacity.

18 Operational GTAs are entered into between pipeline operators and buyers of secondary capacity and will be used to give effect to secondary trades that occur through the capacity trading platform and the capacity purchased through the auction.

19 An electronic exchange allows shippers to anonymously submit bids or offers for standardised capacity products and for those orders to be matched by the exchange. In contrast, a listing service allows shippers to specify any capacity they wish to buy or sell and the price at which they are willing to do so, with any decision to enter into a trade determined through bilateral negotiations.

20 Under a bare transfer, the seller of capacity is responsible for making nominations to the pipeline owner on behalf of the buyer, and complying with the operational and legal obligations imposed by the pipeline under its GTA. Under an operational transfer, the buyer of the secondary capacity is responsible for making nominations and complying with the operational and legal obligations imposed by the pipeline in the Operational GTA.

Table 2 summarises the required, preferred and suggested outcomes with regard to the Commission's transportation capacity markets recommendation, which the GRG would develop.

Table 2 Required, preferred and suggested transportation capacity market outcomes

Recommendation	Required outcomes (included in recommendation)	Preferred outcomes	Suggested outcomes
Auction for contracted but un-nominated capacity	• A daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services. • Auction happens shortly after nomination cut-off time. • Reserve price of zero dollars, with compressor fuel provided by shippers in-kind. • At least all contracted but un-nominated capacity placed for sale through auction. • Accommodate nominations or renominations by incumbent shippers after the auction is conducted.	• Combinatorial auction where multiple buyers and sellers can simultaneously coordinate trades, managing the complementarities between different pipeline segments. • Single round auction to reduce complexity and opportunities for anti-competitive behaviour including collusion between participants. • Bidders pay the value of their winning bids ("first-price" rule) to reduce complexity. • Algorithm determines the winning combination of bids by maximising profit (constrained by requirement that at least all contracted but un-nominated capacity is put on sale in the auction). • Capacity purchased in the auction curtailed before (ie, earlier than) firm capacity. • Single auction across the east coast market, in order to optimise allocation across as many products as possible. • Exemption from the auction for pipelines serving a single user.	• As available rights in current GTAs to be phased out to avoid them competing with rights allocated in the auction. • Exempting on a case-by-case basis pipelines that are not fully contracted from needing to conduct the auction. • The auction to be run by the same instruction(s) which run the capacity trading platform.

Recommendation	Required outcomes (included in recommendation)	Preferred outcomes	Suggested outcomes
Standardisation of key primary and secondary capacity contractual terms	• Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services. • Where possible and appropriate apply across the eastern Australian gas market. • Standards to be developed are for key operational, prudential and other contractual provisions in GTAs, CTAs and Operational GTAs, and provisions in contracts used for exchange based trading on the capacity trading platform. • Counterparties to existing contracts should not be materially disadvantaged through the standardisation process	• Shippers provided greater flexibility to change their receipt and delivery points.	
Capacity trading platform(s)	• Creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms. • Trades carried out through the capacity trading platform to be given effect through an operational transfer. • Bare transfers will be allowed but the seller will be required to offer the buyer the option to use an operational transfer.	• Single capacity trading platform operating across the east coast. • As many services as possible capable of being traded on the platform (eg, transportation services, hub services and pipeline storage services), recognising the need to avoid unnecessary complexities. • Trades conducted outside the capacity trading platform to be advertised ahead of time on the capacity trading platform listing service.	
Publication of information on secondary capacity trades	• Publication of information on all secondary trades of pipeline capacity and hub services. • The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties. • Publication should occur at or shortly after the time the transaction is entered into		

Table 3 provides a summary of how the AEMC's recommendations address matters raised by the ACCC.

Table 3 Summary comparison table of ACCC and AEMC recommendations

Summary of the ACCC's recommendations	How the AEMC's recommendations address these matters
Gas supply	
1. Governments should consider adopting regulatory regimes to manage the risks of individual gas supply projects on a case by case basis rather than using blanket moratoria. 2. Gas reservation policies should not be introduced, given their likely detrimental effect on already uncertain supply.	The AEMC's remit does not cover upstream issues and therefore the Term of Reference for the East Coast review did not extend to specific issues associated with gas supply.
Gas transportation	
3. The current test for pipeline coverage in the Gas Access Regime in the National Gas Law should be replaced with a new test. The COAG Energy Council should ask the AEMC to undertake further consultation and to advise it of the appropriate changes to be made to the test. 4. The COAG Energy Council should ask the AEMC to review Parts 8-12 of the National Gas Rules and to make any amendments that may be required to address the concern that pipelines subject to full regulation may still be able to exercise market power to the detriment of consumers and economic efficiency. 5. The COAG Energy Council should ask the AEMC to explore how the scope of the information disclosure requirements in the NGL should be expanded. The publication of this information would enable shippers to negotiate more effectively with pipeline operators and to identify any exercise of market power more readily.	AEMC Recommendations 5-8 address some of the ACCC's findings in this area. By improving access to transportation capacity in the short term, the AEMC's recommendations are likely to be helpful in mitigating the impacts on market efficiency that the ACCC has found are resulting from monopoly pricing by pipeline operators. The ACCC's findings on the potential issues stemming from monopoly pricing over the longer term, and its conclusion that the existing Gas Access Regime does not effectively target these, are consistent with analysis undertaken by the AEMC in this review. If the COAG Energy Council agrees to progress a review of the Gas Access Regime, the AEMC does not consider that this should preclude or delay the progression of the AEMC's capacity trading market recommendations (Recommendations 5-8).

Summary of the ACCC's recommendations	How the AEMC's recommendations address these matters
Market operation and the level of market transparency	
6. All explorers and producers, including non-ASX listed companies, should report consistent reserve and resource information across the east coast gas market. Reporting should be based on common price assumptions in the calculation of reserves and resources. Gas reserve and resource information should be displayed on the Gas Market Bulletin Board consistent with the COAG Energy Council Gas Market Development Plan to enhance the market information available to Bulletin Board users.	AEMC Recommendation 9 addresses this issue. Consistent with the ACCC's recommendation, the AEMC is proposing that the COAG Energy Council makes law changes and proposes subsequent rule change requests to require that: • all explorers and producers, including non-ASX listed companies, should report consistent reserve and resource information across the east coast gas market; and • gas reserve and resource information should be displayed on the Gas Market Bulletin Board. In progressing the rule changes, the AEMC will consider the ACCC's recommendation for reporting based on common price assumptions.
7. The COAG Energy Council should ensure that the geological and reserve/resource information collected by the states and territories and the Commonwealth, is consistent, non-duplicative and shared. Where this information is made public, the Energy Council should ensure that it is in a consistent format.	Recommendation D of the AEMC's supplementary report on information provision and the Bulletin Board addresses this issue. The AEMC's recommendations relating to additional and consistent reporting requirements on the east coast's Gas Market Bulletin Board will address this issue to a large degree. In making the recommendation, the AEMC has sought to minimise duplication between the information collected by states, territories the Commonwealth, and that which would be required through the Bulletin Board.
8. AEMO should develop and publish a monthly LNG netback price to Wallumbilla, with a clear explanatory framework and inputs. 9. The AEMC should consult with gas users about the potential benefits of requiring AEMO or the AER to publish a periodic price series of actual commodity gas prices paid to producers, either for the east coast generally or for Victoria and Queensland. Any price series should be weighted by volume and be based on commonly observed take or pay percentages and load factors.	The AEMC's Stage 1 Final Report to the Energy Council in July 2015 recommended that the ABS develop a survey-based gas price index, which would show trends in price movements. The ABS has been progressing this recommendation. If this measure is found not to have met its objective of increasing transparency around price movements in GSAs, then the Commission will undertake consultation with industry on additional transparency measures that may be appropriate, including on the ACCC's suggested approach.

Summary of the ACCC's recommendations	How the AEMC's recommendations address these matters
10. The AEMC should consider how to monitor changes in the level of trading flexibility available to gas buyers over time, and how the trading and other risks of having to purchase gas and transportation services on a day-ahead basis can best be managed.	Recommendations 1-4 of the AEMC report will improve liquidity in wholesale markets, including changes to be implemented now and over time. Recommendation 12 of the AEMC report is that the COAG Energy Council tasks the Commission with providing a biennial report on growth in liquidity in wholesale gas and pipeline capacity trading markets, to inform the development of reforms.
11. The COAG Energy Council should monitor the emerging issue of separate gas specifications in the east coast gas market. The COAG Energy Council should ensure that any costs associated with a non-standard gas specification are borne by the market participants that required that alternative specification.	The AEMC has also noted this issue and the proposed design for wholesale gas and trading arrangements reflect the ACCC's views that any non-standard gas specification should be addressed by the market participant and not accommodated within the market design itself.
12. The AEMC should consider requiring the introduction of a centralised capacity trading platform to facilitate secondary capacity trading and day-ahead auctioning of unutilised capacity. 13. The AEMC should consider the benefits of a short-term auction process for hub services if it decides to implement the day-ahead auction for pipeline services.	Recommendations 5 and 7 of the AEMC report address the issues identified by the ACCC in this regard, including coordination problems and transaction costs in the short term capacity market. The AEMC has recommended requiring the introduction of a capacity trading platform(s) to facilitate secondary capacity trading and day-ahead auctioning of unutilised capacity, and for these recommendations to also apply to hub services. To support these recommendations and to further improve secondary capacity trading, the AEMC's recommendations 6 and 8 are for: • the standardisation of key primary and secondary capacity contractual terms for pipelines, hub services, and provisions in contracts used for exchange based trading on the capacity trading platform; and • the publication of information on all secondary trades of pipeline capacity and hub services.

Contents

1 Introduction and context

The gas industry on the east coast of Australia is undergoing a structural change. A collection of largely isolated point-to-point pipelines has evolved into a more interconnected network which supports a series of increasingly interlinked markets.

This process has been accelerated by the commencement of liquefied natural gas (LNG) exports from Queensland, which has driven an increase in overall gas demand and the development of new sources of supply. As LNG is being sold into international markets under contracts linked to oil, the influence of these pricing structures is being felt in the local market, resulting in a shift in domestic demand and consequential impacts on patterns of gas flows. These factors have led to a renewed focus on market development and supply chain efficiency.

Against this background, the Council of Australian Governments (COAG) Energy Council requested that the Australian Energy Market Commission (AEMC or Commission) review the design, function and roles of facilitated gas markets and gas transportation arrangements on the east coast of Australia (the East Coast Review). The purpose of the review has been to consider the role and objectives of the existing markets on the east coast in light of the changing market dynamics and to set out a road map for their continued development.[21]

The Energy Council, at the request of the Victorian Government, also asked the AEMC to undertake a detailed review of the pipeline capacity, investment, planning and risk management mechanisms in the Victorian Declared Wholesale Gas Market (the DWGM Review).[22]

The primary focus of the reviews has therefore been the means of exchange for gas: how physical and financial transactions take place between buyers and sellers. Although providing important context for the reviews, issues relating to gas production or levels of competition in the production sector largely fall outside of the Commission's remit and have been considered by other bodies, which we have been working and consulting with closely.[23]

1.1 Changing market dynamics are driving a need for greater flexibility

Historically, natural gas on the east coast has been traded through long-term bilateral gas supply agreements (GSAs). These contracts have traditionally covered periods of 15 to 20 years in order to underwrite investments in capital intensive, long-lived assets.

21 COAG Energy Council, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Terms of Reference, 20 February 2015, p. 1. See Appendix A.

22 See: COAG Energy Council and Victorian Government, *Review of the Victorian Declared Wholesale Gas Market*, Terms of Reference, 4 March 2015.

23 In particular, as discussed in section 1.1.1, the Australian Competition and Consumer Commission (ACCC) has undertaken an inquiry into Eastern and Southern Australian wholesale gas prices. In addition, the COAG Energy Council has been developing its Gas Supply Strategy.

As noted by the ACCC Inquiry, gas supplied under long-term GSAs was historically priced using a cost-plus formula, in which the contract price paid for gas by users was calculated based on the cost of production and escalated with inflation.[24]

A number of facilitated gas markets have been developed on the east coast, including the Declared Wholesale Gas Market (DWGM) in Victoria and the Short-Term Trading Market (STTM) hubs in Adelaide, Brisbane and Sydney. However, in a relatively stable environment where the majority of gas was transacted through bilateral contracts, the primary role of these markets has been to manage daily imbalances. Participants that provided evidence to the ACCC Inquiry reinforced this, noting the following regarding the STTM:[25]

> "Most of the traded volumes were to adjust imbalances between expected and actual supply or demand and the prices only reflect short-term day to-day-conditions, rather than the underlying supply and demand conditions for gas supply. The short-term prices in these markets were not regarded as providing a guide to actual market prices which could be reflected in bilateral supply negotiations."

The current environment is now subject to rapid change. Between 2014 and 2016, gas demand on the east coast will have increased threefold, driven by LNG exports.[26] This substantial increase in demand has put upward pressure on domestic gas prices. In addition, as many export contracts are linked to international oil prices, there has also been a growing trend to link domestic gas prices to oil, presenting a new and unfamiliar risk for gas consumers to manage.[27]

Further, this period of volatility has coincided with the expiry of many domestic long-term GSAs,[28] raising questions around the market's resilience to such significant changes. Market participants now require greater flexibility in how they buy and sell gas outside of bilateral gas contracts and new approaches to risk management. The need for such levels of flexibility was largely unforeseen at the time the current market frameworks were developed.

Evidence presented to the ACCC Inquiry supports the view set out by the Commission in the Stage 1 Final Report that the current market frameworks are unlikely to provide participants with the trading options and flexibility going forward. The ACCC noted the following:[29]

> "Producers provided evidence to the Inquiry that they did not have sufficient confidence in the maturity of STTMs to provide them with a level of price and volume certainty that would enable them to supply significant

24 ACCC, Inquiry into the east coast gas market, April 2016, p. 29.

25 ACCC, Inquiry into the east coast gas market, April 2016, p. 78.

26 AEMO, *National Gas Forecasting Report*, 2015.

27 ACCC, Inquiry into the east coast gas market, April 2016, pp. 31-32.

28 Department of Industry, Innovation and Science, *Gas Market Report 2015*, p. 40.

29 ACCC, Inquiry into the east coast gas market, April 2016, p. 78.

> volumes of gas on these markets. Similarly, many buyers are concerned that trading gas will increase, not decrease, their overall average gas price if demand on the DWGM or STTMs increases significantly."

While bilateral contracts will remain a fixture of the market, more flexible and sophisticated means of managing gas portfolios are becoming increasingly important to market participants due to:

- rising GSA contract prices, inducing participants to seek to reduce their average gas supply costs through market-based trading;
- reduced load factor flexibility and/or increases in the pricing of flexibility in GSAs, providing an incentive to utilise trading markets to procure flexibility;
- spot price volatility, resulting in arbitrage opportunities that participants might seek to benefit from.

Each of these factors is discussed further below.

1.1.1 Upward pressure on GSA contract prices

A number of retailers and large industrial users across the east coast have claimed that it has become more difficult and expensive to enter into GSAs since the establishment of an LNG export industry in Gladstone. In response, the Australian Government directed the Australian Competition and Consumer Commission (ACCC) to conduct an inquiry of wholesale gas prices in eastern and southern Australia.

Box 1.1 ACCC inquiry into the east coast gas market

The ACCC was tasked with conducting an inquiry into the east coast market on 8 April 2015. Under its terms of reference, matters to be taken into consideration included:[30]

- the availability and competitiveness of offers to supply gas and the competitiveness and transparency of gas prices;
- the competitiveness of, access to, and any restrictions on market structures for gas production, gas processing and gas transportation;
- the significance of barriers to entry into the upstream production sector;
- the existence of, or potential for, anti-competitive behaviour and the impact of such behaviour on purchasers of gas; and
- transaction costs, information transparency including gas supply contractual terms and conditions, and other factors influencing the competitiveness of the markets.

The ACCC inquiry and AEMC reviews are complementary, with the ACCC having much broader information gathering powers than the AEMC. We have worked closely with the ACCC to ensure co-ordination between the two processes, and the ACCC's findings have been helpful in informing our considerations regarding market development.[31]

In its report, published in April 2016, the ACCC found that domestic purchasers of gas, particularly industrial users, experienced an "unprecedented" change in their ability to obtain gas, especially in the period from about 2012 to the end of 2014 for gas to be supplied in 2016 and beyond. Few, if any, "real" gas offers were received, and those offers tabled were high priced, with limited volumes over short periods of time.[32]

While the ACCC reported that more gas supply offers are now available, it also emphasised that the market will not revert to its previous state. All market participants are exposed to international LNG and oil prices, and the offers that are now made to users tend to be at higher prices and for shorter durations than previously.[33]

The ACCC's findings suggest that LNG exports have resulted in a tightening in the supply and demand balance and upward pressure on wholesale gas prices, which

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30 Australian Government, *Inquiry into competitiveness of the Wholesale Gas Industry*, Terms of Reference, 8 April 2015, p. 1.

31 Under section 157A of the Competition and Consumer Act, the ACCC may disclose to the AEMC information that it has obtained under the Act that is relevant to the AEMC. The two organisations therefore put procedures in place to allow such information to be shared in this instance.

32 ACCC, Inquiry into the east coast gas market, April 2016, p. 18.

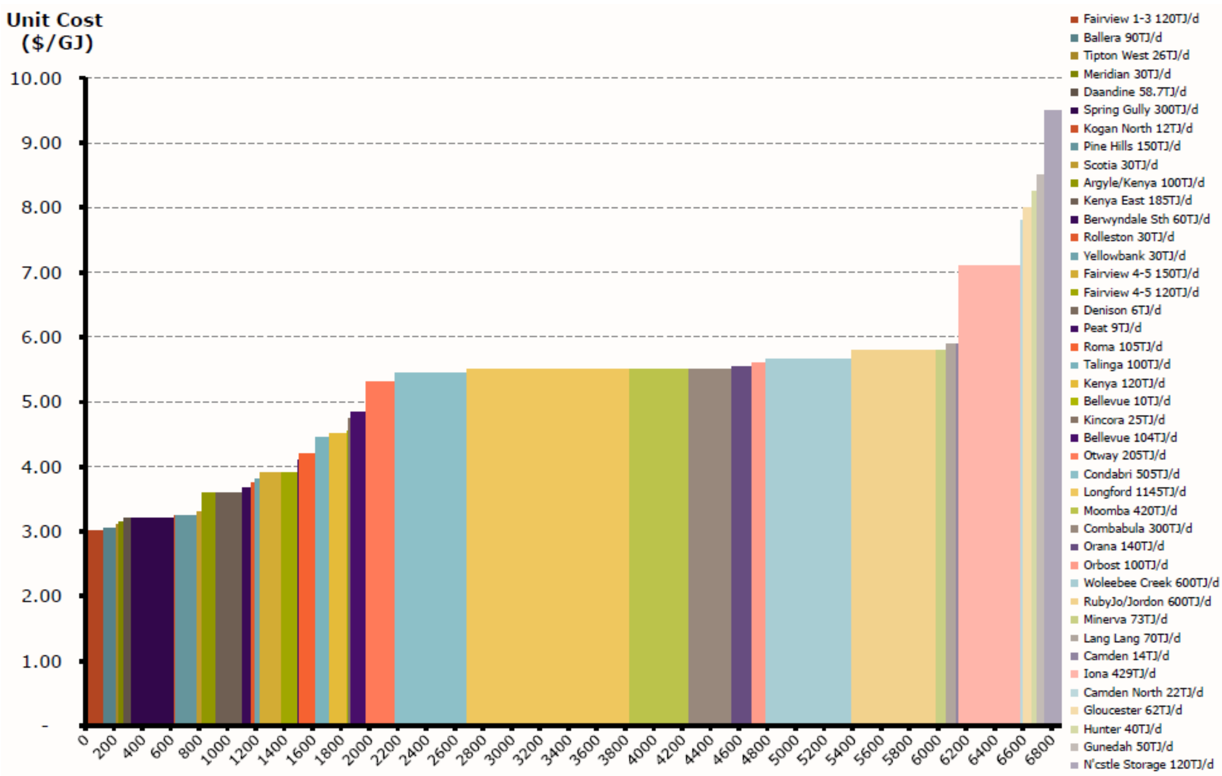
33 ACCC, Inquiry into the east coast gas market, April 2016, pp. 18 and 29-31.

should provide an incentive for producers to offer more supply to the market. However, restrictions and inquiries into gas field exploration and development, which currently exist in a number of jurisdictions, could restrict this response, resulting in higher wholesale prices than would otherwise have been the case if moratoria were not in place.[34]

The ACCC consequently recommends that governments consider adopting regulatory regimes to manage the risks of individual gas supply projects on a case by case basis rather than using blanket moratoria.[35] The effects of moratoria can include higher gas costs, as a result of developing less productive or more expensive gas reserves. This will contribute to higher prices paid by consumers.

The Commission also notes that increasing development costs will add to upward pressure on gas prices. Figure 1.1 shows an indicative gas supply cost curve for the east coast market.[36]As lower cost gas reserves are developed and consumed, higher cost reserves will need to be brought online. Unless there is a change in technology that lowers extraction costs, an increase in supply in response to higher prices may not result in a reversion back to historic price levels due to increased production costs.

Figure 1.1 Indicative east coast gas supply cost curve



Source: Simshauser, P. & Nelson, T. 2015,*The Australian east coast gas supply cliff*, Economic Analysis and Policy, p. 78.

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34 ACCC, Inquiry into the east coast gas market, April 2016, pp. 65-66.

35 ACCC, Inquiry into the east coast gas market, April 2016, p. 20.

36 The horizontal axis shows the maximum theoretical quantities capable of being produced by each supplier (TJ/day), while the vertical axis shows cost of production ($/GJ).

1.1.2 Reduced flexibility in GSAs

Another observation by the ACCC is that supply offers now tend to have more restrictive terms and conditions, in particular the amount of flexibility being provided to users. The ACCC has provided insight on this in the following way:[37]

> "The Inquiry has observed that, overall, flexibility under new GSAs is lower than has been previously offered and that flexibility is more expensive. The reduced flexibility has occurred in a number of ways, including an increase in the take-or-pay multiplier, a reduction in the load factor, GSAs being offered with a defined load profile throughout the year, and the removal or limiting of banking provisions in new GSAs."

GSAs have traditionally included a degree of flexibility in the quantity of gas a buyer can take on any day to cater for variability in their demand. Specifically, such contracts usually include a "take or pay" amount that the buyer must take or else they will be charged for that amount regardless, as well as a load factor that measures the extent to which a buyer can take more than the average daily contract quantity throughout the year.[38]

The load factor typically ranges from 100 to 125 per cent. A value of 100 per cent implies the buyer can only take its average daily contract quantity; while a value of 125 per cent implies that the buyer can vary its daily consumption by +/-25 per cent on any day, subject to the constraint that it only takes its annual contract quantities over the year.[39]

Flexibility in GSAs can be expensive for producers, as the production facility, and associated capital, is underutilised outside peak periods. With the start of LNG exports and consequent increase in demand, producers may seek to run their plants at higher capacity factors and become more reluctant (that is, charge a higher price) to offer bilateral contracts to gas users with the amounts of supply flexibility traditionally offered.

In this context, it is essential that alternative trading mechanisms are developed to:

- allow shippers to easily sell additional contracted gas outside of their peak periods; and/or
- provide a mechanism for shippers to purchase gas on a short term basis to meet their peak demand.

Buyers who wish to manage their gas demand outside of a GSA will need to find a balance between a minimum level of gas sourced through bilateral contracts and the volume sourced through market trading. This is illustrated in Box 1.2.

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37 ACCC, Inquiry into the east coast gas market, April 2016, p. 71.

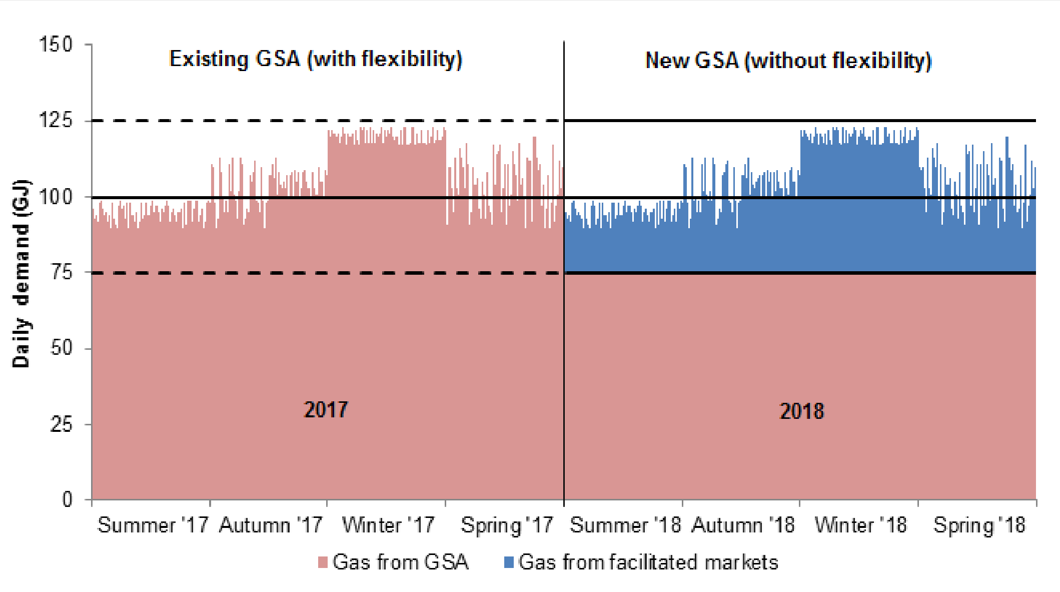
38 Take or pay provisions may also include a 'make-up' provision, allowing a user to take gas at a later date that is not used in the current period.

39 K Lowe Consulting, *Gas Market Scoping Study: A report for the AEMC*, July 2013, p. 43.

Box 1.2 Reduced flexibility in GSAs will support trading liquidity

The figure below illustrates the demand for gas by a representative market participant over a two year period, where the first year (2017) they are counterparty to the type of GSA traditionally offered by producers on the east coast. In the second year (2018) they have had to enter into a GSA with less flexibility or load factor. The representative market participant in this example expects peak demand to correspond to the winter months.

Figure 1.2 Sourcing of gas supplies under GSAs of different flexibility



The retailer has an average expected daily demand of 100GJ. The existing contract includes swing factors to allow the participant flexibility of +/-25 per cent, ie, so that they can take anywhere between 75 and 125GJ per day under the contract. As illustrated in the left-hand panel in Figure 1.2, this results in the participant being able to procure all of the required gas from within the confines of its contract in 2017.

In this stylised example, this flexibility is not available or prohibitively costly by 2018. Participants may therefore decide to:

1. Continue to have a GSA for expected average daily demand and buy or sell gas around this in the spot of forward markets as required. This is illustrated by the solid black line corresponding to 100GJ per day in 2018.

2. Enter into a GSA for delivery of gas at a fixed price to meet expected *maximum* demand and sell any excess gas on a trading market in the spot of forward markets. This is illustrated by the solid black line corresponding to 125GJ per day in 2018.

3. Enter into a GSA for delivery of gas at a fixed price to meet expected *minimum* demand and rely on buying gas from the trading market to satisfy demand above this minimum level. This is illustrated by the solid black line corresponding to 75GJ per day in 2018.

In this example, the participant opts to only contract for 75GJ of expected average daily demand of 100GJ. The blue area in the figure therefore shows the amount of gas the participant is aiming to procure through short term trading.

1.1.3 Spot price volatility

Exposure to international LNG and oil prices has increased not only the level, but also the volatility, of domestic gas prices in the east coast market.[40] These external drivers, combined with the variability inherent in Coal Seam Gas (CSG) supply, are from time to time likely to result in price differentials between the hubs.

Price volatility is likely to:

- provide participants with commercial opportunities to arbitrage gas prices between trading markets on the east coast, as well as between their bilateral contract price and trading market prices; and
- increase the demand for financial derivatives to manage the increased price risk on the trading markets.

Price volatility can be profitable for participants prepared to take advantage of opportunities at short notice, where mechanisms exist that allow them to do so. Where the gas price is low and participants are able to substitute contract gas with spot gas, inject gas into storage and/or build inventory by increasing production at a factory, this promotes the efficient allocation of gas in response to price signals. The Commission's recommended roadmap for gas market development is intended to support this trading flexibility.

The corollary of using trading markets more actively to procure supply flexibility, and as a credible alternative to bilateral contracts, is a greater exposure to market prices. While participants may have been comfortable managing spot price risk within the flexibility of a physical GSA position, in the future this may not be possible as either suppliers are no longer able to offer this flexibility in Gas Supply Agreements or the premiums attached to such flexibility are not commercially attractive for gas users.[41] As a consequence, there is likely to be a greater need for market-based financial derivative products to hedge price risk from market-based trading.

40 ACCC, Inquiry into the east coast gas market, April 2016, p. 36.

41 ACCC, Inquiry into the east coast gas market, April 2016, p. 14.

1.2 Meeting the Vision will benefit consumers and is achievable

Increased flexibility through shorter term trading of gas will require a gas market that is able to foster liquid trading and support the development of risk management products. This has been recognised by the COAG Energy Council, and is reflected in the Council's Vision for Australia's future gas market.

Released in December 2014, the Vision is as follows:[42]

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

The work of the Commission through this review has been to develop a roadmap for gas market development that allows the Vision to be met. The review has been structured over two stages:

- **Stage 1** outlined the overall direction for the east coast market development, including a fact base of current market outcomes and a gap analysis between the COAG Energy Council's Vision for Australia's future gas market and the existing arrangements, as well as setting out a number of recommendations that could be progressed in the short-term (see Appendix D); and

- **Stage 2** more fully develops medium and long-term adjustments required to implement the Vision, including the transition path required.

The Vision provides a high level policy statement that has guided the analysis undertaken in this review, focused on key outcomes for the gas market that are necessary to meet the National Gas Objective (Box 1.3). The achievement of the Vision is an important objective given the changes occurring in the gas market and the likely inability of the current market arrangements to accommodate these changes.

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42 COAG Energy Council, *Australian Gas Market Vision*, December 2014, p. 1.

Box 1.3 The National Gas Objective

The National Gas Objective (NGO) underpins all of the Commission's work and is set out in section 23 of the National Gas Law (NGL). It states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The NGO is structured to encourage energy market development in a way that supports the:[43]

1. efficient allocation of natural gas and transportation services to market participants who value them the most, typically through price signals that reflect underlying costs;

2. provision of, and investment in, physical gas and transportation services at lowest possible cost through employing the least-cost combination of inputs; and

3. ability of the market to readily adapt to changing supply and demand conditions over the long-term by achieving outcomes 1 and 2 over time.

The three limbs of efficiency described above are generally observable in a well-functioning, workably competitive market and together work to promote the long-term interests of consumers of natural gas.

In accordance with the NGO, the Commission has taken into account the long term interests of all consumers of natural gas throughout this review. We note that there are numerous types of consumers of natural gas in the Australian economy, including: residential and commercial users; industrial and manufacturing users; gas fired generators; and LNG producers.

The Council's Vision can be broken into three key outcomes:

- Establishment of an efficient and transparent reference price for gas.
- Participants able to readily trade gas between hub locations.
- Investment in infrastructure that responds to market signals and is facilitated by a supportive regulatory framework.

The achievement of the Vision requires the creation of a self-reinforcing cycle that encourages both the demand and the supply side of the market to participate.

43 These three outcomes are commonly referred to as allocative, productive and dynamic efficiency, respectively.

Trading markets that are simple, low cost and easy to use will encourage producers and users to enter and participate. More participants and greater traded volumes leads to more meaningful pricing signals, giving producers more confidence that they will have a market for their supply. Increased supply gives buyers sufficient confidence to augment their contracts with traded gas from the market. As trading volumes increase, financial risk management tools can be developed, further strengthening confidence in the market - this cycle is illustrated in Figure 1.3.

The sections below define 'liquidity' and discuss in more detail the benefits of a liquid wholesale gas market.

Figure 1.3 Establishing a liquid trading market

1.2.1 Benefits and characteristics of a liquid wholesale gas market

A liquid trading market facilitates the buying and selling of gas on an equal basis to other players, and the hedging of price risk, which lowers barriers to entry and promotes competition. Trading gas through well-functioning markets is also fundamental to consumers being able to know whether the gas price reflects underlying demand and supply.

An effective gas market is one that can deliver a meaningful, market-based reference price for natural gas that reflects underlying supply and demand conditions. Such a price can provide signals to drive the efficient use of gas in the short-term, while promoting efficient levels of investment in physical supply in the long-term.

A credible market price can also be referenced in bilateral contracts. While counterparties agree a volume to be delivered over a defined time frame, the price paid on any given day is a function of a floating reference price in a trading market - for example, the day-ahead price at the Northern Hub. This reduces transaction costs by making negotiating GSAs simpler, without the need to determine complex pricing formula and undertake gas price arbitrations.

An efficient market-based reference price for gas that is credible in the eyes of participants requires sufficient trading liquidity. Liquidity is commonly defined based on four characteristics:[44]

- **Market depth:** where no single buy or sell order is likely to move the market price excessively.
- **Market breadth:** where a large number of bids to purchase gas and offers to sell gas are present in the market.
- **Immediacy:** the ability to trade large volumes in a short period of time.
- **Resilience:** the ability of the market to recover towards its natural equilibrium after being exposed to a shock.

In a liquid gas market, individual trades can be easily satisfied and would not by themselves cause the price to change significantly. Unless participants are confident that the market price represents the underlying value of gas, then physical and financial participants will be unwilling to offer risk management products. This will, in turn, decrease the attractiveness of purchasing gas on the market or indexing a bilateral contract to the market price, as the price risk cannot be effectively hedged.

Market outcomes are also a function of the quality of information available to market participants. A liquid gas market in which the reference price is an accurate reflection of the value of gas aids commercial decision-making. Where accurate information is available it allows market participants to act upon their preferences and allows for trade-offs to be accurately assessed. A liquid forward and future market also provides market participants with useful information on expectations of future price developments and allows them to formulate appropriate strategies to manage risks.

Importantly for the Australian context, a liquid wholesale gas market can lower barriers to entry and encourage new entrants on both the supply and demand side of the market. Where gas and pipeline capacity is sold predominantly through bilateral contracts, it may be difficult for new producers or gas users to enter the market, as they may not have the resources to negotiate on an equal basis with incumbents.

In a liquid market, new entrants - whether they may be small producers or gas users - have accurate price information and can readily buy or sell gas on a market on an

44 IEA 2008, Development of competitive gas trading in continental Europe – How to achieve workable competition in European gas markets?, IEA Information Paper, May, p. 46.

equal basis to other players. Liquid markets can therefore encourage participation and promote competition.

Similarly, a liquid market can reduce transaction costs as buyers and sellers are matched on the market. This reduces search costs as sellers and buyers no longer need to incur the costs associated with searching for and negotiating an agreement with a counterparty. Buyers and sellers in a liquid market can trade frequently at low cost and at a price that is reflective of the "true value" of gas based on underlying supply and demand dynamics.

It is clear from the discussion in section 1.1 that the gas market is undergoing fundamental change, which is likely to have the following implications for the market:

- The potential lack of flexibility in GSAs in the future will mean that more gas will be procured through trading markets.
- The shorter term nature of gas contracts will mean that market participants will need to engage in a larger number of transactions to satisfy their demand for, or sell their supply of, gas.
- Gas users, who have previously sourced all their gas demand through bilateral contracts, may now trade on a market for the first time - increasing the number of market participants.

As more gas is traded on the market, participants will have confidence that the market price is a reflection of the true value of gas. As market-based trading becomes more common place, corporate experience in trading gas will grow, fostering a trading culture common in other commodity markets.

1.2.2 Size of east coast market not a barrier to increasing liquidity

A liquid wholesale gas market requires different types of buyers and sellers transacting sufficient volumes of gas to support trading liquidity. In practice, this implies that participants use gas in different ways and therefore have incentives to trade with each other in response to a common price signal.

The east coast gas market is made up of many different players from numerous industries and gas is used in a variety of ways by these participants. The amount of gas used by each participant is dependent on their particular circumstances.[45] Common consumption profiles for gas users include:

- **Residential Customers:** Consumption of gas by residential customers can be variable in areas subject to a distinct seasonal influence. Gas demand will be higher in winter and therefore demand can be volatile at this time of year. In areas with a more temperate climate, gas demand is more stable throughout the

45 K Lowe Consulting, Gas Market Scoping Study: A report for the AEMC, July 2013.

year. Households purchase gas from retailers who participate in the wholesale gas market; these retailers may therefore have a variable demand profile.

- **Large industrial consumers:** Generally these consumers have a relatively flat consumption profile. However they may have the ability to change the level of production at their facilities and could therefore increase or decrease their demand for gas. These customers are influenced by conditions in the market for their products but are also affected by input costs, including the wholesale price of gas. This category of gas users includes LNG producers.

- **Mining facilities:** These gas users can have a "lumpy" gas consumption profile, meaning that consumption levels can increase or decrease by a large amount at short notice. Mining facilities trade on international commodity markets and must be able to react to changes on these markets.

- **Gas-fired generators:** The consumption profile of a particular generator is dependent on its type. Base-load and intermediate gas-fired generators have relatively predictable consumption profiles, while the consumption profile for peaking plant is less certain and therefore more volatile.

As renewable generation becomes a larger part of the energy mix, gas-fired generation is expected to play a more prominent role in supporting the intermittent nature of wind and solar power. Flexible trading arrangements for gas support the uptake of renewable generation as they allow participants to respond more efficiently when gas-fired generation is required. For instance, instead of making a major investment decision to enter into a large GSA, businesses will be able to supplement smaller and less risky GSAs will gas procured from trading markets. This will support more efficient optimisation of gas portfolios to gas-fired generation operations.

Market participants' consumption profiles vary in different ways over time. A liquid wholesale gas market allows these diverse market participants to balance their gas requirements while providing commercial opportunities to trade on the wholesale market.

In addition, each jurisdiction on the east coast exhibits fundamental differences in gas usage. These jurisdictional differences in gas consumption can provide additional opportunities to trade and complement the variability in demand profiles between market participants and is demonstrated in Box 1.4.

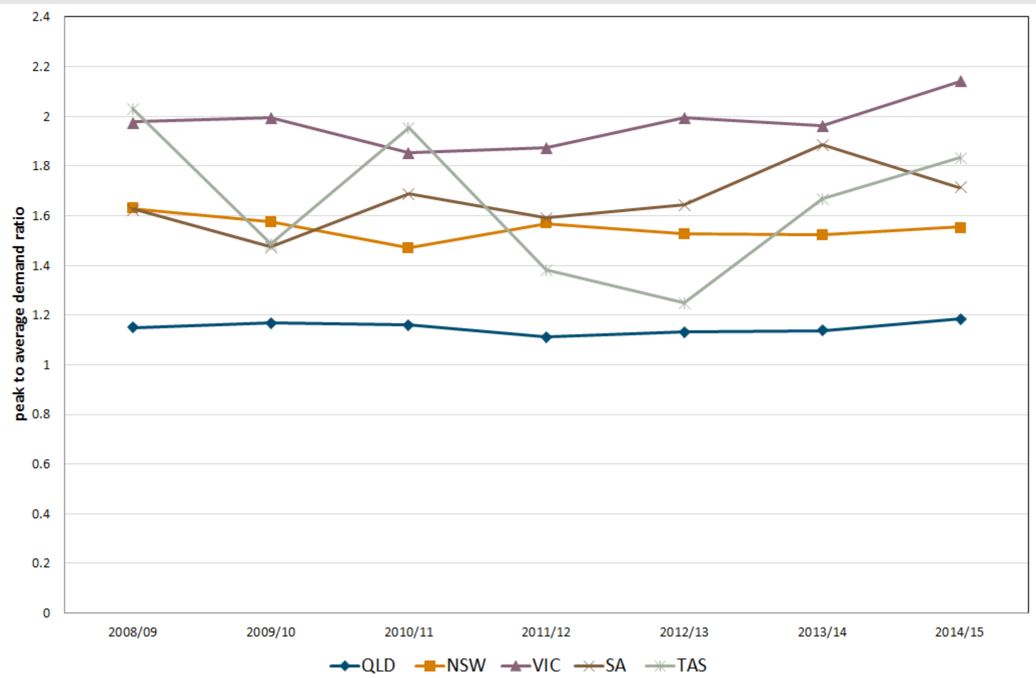
Box 1.4 Changes in demand profiles across jurisdictions

The differences between jurisdictions' demand for gas is based on how gas is used in that region; for example, how large the residential and small to medium enterprise sector is relative to gas-fired generation or industrial users. The weather also has an effect on regional demand profiles, as gas is used to heat homes and business, and conditions can affect electricity demand, which has an indirect effect on gas prices through demand from gas-fired generators.

Figure 1.4 shows the peak demand to average demand ratio for jurisdictions on the east coast. Victoria, with its large proportion of residential gas consumers, has the highest peak to average demand ratio due to the increase in gas demand in winter months. Queensland has the lowest ratio, as gas demand is largely attributable to industrial users with relatively flat consumption profiles.

These seasonal differences make it important for gas to be able to flow efficiently between jurisdictions. When electricity demand in Queensland is high in the summer months, this will drive an increase in gas used for gas-fired generation. Conversely, when the weather is cold in Victoria during winter months, this will drive gas demand for space heating. An interconnected system where gas and pipeline capacity is easily tradeable allows demand for gas to be met at least cost.

Figure 1.4 Ratio of peak to average gas demand by jurisdiction, 2008-2015[46]



Source: AER Wholesale Statistics.

46 Volatility in Tasmania is likely due to seasonal fluctuations amplified by the small size of the market.

Based on AEMO registration data, there are currently:

- 25 market participants in the DWGM;
- 22 market participants in the Sydney STTM hub;
- 15 market participants in the Adelaide STTM hub;
- 11 market participants in the Brisbane STTM hub; and
- 17 at the Wallumbilla Gas Supply Hub (GSH).

With a number of legacy GSAs rolling off over the next two to three years, and higher priced and less flexible GSAs being offered by suppliers, the number of large users seeking the flexibility provided by trading markets is likely to increase. The Commission has received feedback through submissions from major users that the current facilitated markets are adding value to their gas procurement activities. Visy, Qenos, Australian Paper and CQ Partners have submitted that the existing facilitated markets play an important role in providing major users access to wholesale gas at the city-gate.[47]

Some participants are currently only registered at the hubs where they directly consume gas, which limits their ability to take advantage of price differentials between the hubs. For instance, there are participants registered with the Wallumbilla GSH and Brisbane STTM, but not the DWGM. Feedback from stakeholders suggests that the existence of multiple hub designs creates complexity, costs and inefficiencies which, as observed by one participant, is likely to discourage greater participation outside of retailers in major demand centres.[48] Multiple markets with different designs have therefore hindered the development of liquidity across the east coast and limited the ability to develop risk management tools outside of bilateral contracts. A fully integrated east coast gas market, with greater harmonisation of market mechanisms, would provide all suppliers and users of gas with an opportunity to easily participate at any of the hubs in order to realise commercial benefits.

All participants should have a realistic ability to engage in market trading in accordance with their needs and in response to price signals. Trading markets are not expected to replace GSAs, but provide an additional means of buying and selling gas. As gas can be traded multiple times between each participant before being used, this fosters a dynamic and liquid market where participants can continually trade gas to optimise their portfolios.

47 Wholesale Gas Markets Discussion Paper Submissions: Visy, pp. 4-5; and Qenos, pp. 2-4. Stage 1 Draft Report Submissions: Australian Paper, pp. 2-3; and CQ Partners, pp. 1-3.

48 GDFSAE, AEMC Public Forum Discussion Paper submission, pp. 8-9; QGC, AEMC Public Forum Discussion Paper submission, p. 6.

1.2.3 Market frameworks must evolve to help liquidity develop

A critical enabler for the development of a liquid gas market, particularly in an environment with relatively few, geographically dispersed producers and users, will be the ability of gas to flow easily across the pipeline system to where it is valued most highly. If there are obstacles to participants being able to access transportation capacity, this will inhibit their ability to move gas to market in order to trade it, diminishing liquidity.

While existing gas transportation arrangements based around long-term bilateral contracts have supported substantial investment in pipelines to date,[49] the significant increase in volatility of gas flows across the transmission network is highlighting the lack of flexibility embodied in these arrangements. For example, the potential for outages at the LNG production facilities, combined with the variable nature of the coal seam gas wells supplying them, may lead to occasions where significant amounts of gas will need to be redirected to different uses, and to users who may value the gas more.

While the Commission understands that the rights to use pipeline capacity are sometimes reallocated between participants for periods of 6-12 months, it has seen little evidence that shorter-term capacity trades occur.[50] Indeed, the ACCC has found that the transaction costs involved in such trades can be prohibitive.[51] While pipeline owners can and do resell unused short-term pipeline capacity, the lack of competition in this market provides few limitations on the price set for that capacity.[52]

Consequently, inefficiencies in the market for short-term pipeline capacity are likely to represent a major barrier to the development of liquid gas trading markets with prices that can respond to short-term shifts in supply and demand. Much of the Commission's work in this review, therefore, has been to understand the linkage between pipeline capacity and gas commodity markets, and to identify opportunities to develop the frameworks to allow pipeline capacity to be reallocated in ways that would support the efficient trading of gas.

The importance of pipeline capacity to supporting an efficient gas market is illustrated in the example in box Box 1.5.

49 Different arrangements for investment in pipelines apply in the DWGM . See: AEMC, *Review of the Victorian Declared Wholesale Gas Market*, Draft Report, 4 December 2015, Chapter 2.

50 ACCC, Inquiry into the east coast gas market, April 2016, p. 144.

51 ACCC, Inquiry into the east coast gas market, April 2016, pp. 151-152.

Box 1.5 The importance of pipeline capacity to supporting an efficient gas market

Once the LNG plants are fully operational they will consume around 4,000 TJ of natural gas per day on average. This compares to average daily consumption on the east coast of approximately 1,800 TJ per day and for Queensland an average of approximately 600 TJ per day.[53]

If one of the six LNG trains unexpectedly shuts down due to a fault, CSG production to meet the expected LNG demand may be able to be turned down by around 80 per cent, with further reductions potentially not technically feasible.[54] However, this still leaves approximately 130 TJ of gas to be absorbed by the domestic market – equivalent to seven per cent of average daily gas demand for the east coast, or 22 per cent of Queensland demand.

This excess gas might be bought by GFG generators, who are able to respond quickly to high gas supply and low gas prices. Other gas might be put into storage. However, in order for this to happen, one or other of the counterparties to the trade must quickly secure transportation capacity rights between where the gas is and where it is needed. If this gas is to be traded outside of Queensland it must be shipped westwards on the South West Queensland Pipeline, which has a capacity of approximately 385 TJ per day.[55]

If sufficient capacity is not available through an existing Gas Transportation Agreement, the counterparties have two options: purchase capacity from another shipper (secondary capacity) or purchase capacity directly from the pipeline owner, typically as "as-available" capacity (capacity that is otherwise contracted to another shipper but which is not being used).

However, limitations in the current short-term capacity market make these options difficult:

- The short-term secondary market is illiquid, and has high search and transaction costs (for example, finding and then negotiating a trade with an incumbent shipper is time consuming).
- Evidence collected by the ACCC suggests that the prices charged by some pipelines for as available capacity is excessive (for example, 185 to 300 per cent of the firm transportation charge).[56]

The difficulties in accessing secondary capacity and the prices of as-available may preclude otherwise commercially viable capacity trades, and hence the trade of gas. Timely and reasonable price access to capacity is crucial for an efficient gas market.

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52 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 147-148.

53 AEMO, *National Gas Forecasting Report*, December 2015, pp. 3, 60.

54 If CSG wells are turned down too far then they risk filling up with water and ceasing production until this addressed. Individual turn down rates vary by CSG field.

55 http://apa.com.au/our-business/energy-infrastructure/queensland.aspx, accessed 20 May 2016.

56 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 108-110.

To complement this, the Commission has considered options for the location and design of facilitated wholesale markets. Liquid trading is most likely to develop where there is a diversity of producers and users, and potentially other services that facilitate trading (such as storage). This implies that the existing STTM hubs, located at demand centres, are unlikely to be the best locations to seek to develop liquid trading markets. Similarly, the current STTM design, which mandates that all physical trading takes place on a day-ahead basis, does not provide options for flexible trading and is unlikely to support the development of risk management products.

For markets to function efficiently they require participants to have accurate and timely information to aid decision making. This allows participants' preferences to be acted upon, and informed trade-offs to be made. Market outcomes will partially be a function of the information on which participants are able to act, and this is therefore also an important consideration in the development of market frameworks.

Consequently, consistent with the terms of reference for the review, this report sets out the Commission's final recommendations to support improved price discovery and liquidity in wholesale markets. Underpinned by enhancements to regulatory frameworks to facilitate the more efficient usage of pipeline capacity, these measures would put in place the preconditions to allow more effective risk management tools to develop.

In addition, the Commission has reviewed the frameworks for information provision in the context of the current market arrangements. While a summary of the Commission's findings are provided in this report, the full recommendations are set out in a separate report, reflecting the more detailed and immediate nature of this work.[57]

1.3 Ethane markets and pipeline arrangements

The NGL and NGR regulate the trading of natural gas and natural gas services. Natural gas is defined in the NGL as a substance in a gaseous state consisting of naturally occurring hydrocarbons with methane as its principal constituent.[58] The NGL also defines processable gas, which is natural gas in a form not yet suitable for consumption.[59] A variety of other chemicals including ethane are present in natural gas as minor constituents.

Some stakeholders have raised concerns regarding a lack of regulation in the sector, the level of liquidity in the ethane wholesale market, a lack of access and liquidity in the ethane pipeline capacity market, and limited information on which to make informed

57 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report: Information Provision, December 2015.

58 NGL, Chapter 1, Part 1, section 2.

59 NGL, Chapter 1, Part 1, section 2.

commercial decisions.[60] Background to the production and use of ethane on the east coast is in Box 1.6.

Ethane that is isolated from natural gas is by definition not natural gas as defined in the NGL, and as such the NGL and the NGR do not apply to it. This means, for example, that the Gas Access Regime under the NGL and the Natural Gas Services Bulletin Board do not apply to ethane infrastructure or markets. As the Commission's remit does not extend to ethane, this issue has not been considered as part of the review. Nevertheless, the COAG Energy Council may wish to consider these matters further.

Box 1.6 Ethane production and use on the east coast

While ethane is a flammable gas (like methane) and so a useful energy source, it is also used as a feedstock to certain chemical processes for which methane is unsuitable for – most notably in the production of ethylene and polyethylene (plastics). For these purposes, ethane is isolated from natural gas.

In contrast to the east coast natural gas market, ethane is currently only produced by two suppliers in the east coast: the Cooper Basin Joint Venture (JV) and the Gippsland Basin JV.[61] Ethane produced by the Gippsland Basin JV is supplied directly to users in Altona via the Long Island to Altona Pipeline, which is owned and operated by Esso.[62]Production from the Cooper Basin JV, on the other hand, is currently supplied by Santos and Origin to Qenos,[63] who then transports the ethane to its Botany facility via the 1,375 km Moomba to Sydney Ethane Pipeline owned by the Ethane Pipeline Income Fund.[64]

Estimates developed by EnergyQuest indicate that approximately 23 PJ of ethane was produced in the 12 months to December 2015, of which 55 per cent was produced in the Cooper Basin and the remaining 45 per cent in the Gippsland Basin.[65]

1.4 Structure of this report

This is the Final Report of Stage 2 of the Commission's review of east coast gas markets. The remainder of the document is structured as follows:

- Chapter 2 provides a summary of the Commission's overarching findings and recommendations in order to achieve the Vision;

60 See, for example, submission on to the Stage 2 Draft Report: PACIA, p. 2.

61 EnergyQuest, *EnergyQuarterly*, March 2016, p. 111.

62 The Australian Pipeliner, *Victoria's productive pipelines*, 16 March 2016.

63 Santos Media Release, *Qenos contract secures continued gas supply and jobs*, 13 November 2014.

64 The Australian Pipeliner, *The Moomba to Sydney Ethane Pipeline*, 16 March 2016 and Ethane Pipeline Income Fund website http://ethanepipeline.com.au/investor-centre/qa.aspx

65 EnergyQuest, *EnergyQuarterly*, March 2016, p. 111.

- Chapter 3 sets out how the recommended package of reforms should be progressed;
- Chapter 4 discusses the Commission's findings and recommendations with regard to transportation capacity markets in detail;
- Chapter 5 provides a more detailed overview of the Commission's wholesale gas market recommendations; and
- Chapter 6 is an overview of the Commission's findings and recommendations with regard to information provision and the Gas Services Bulletin Board.

The report also contains a number of appendices, as follows:

- Appendix A: Terms of reference;
- Appendix B: Assessment framework;
- Appendix C: Review process;
- Appendix D: Update on Stage 1 recommendations;
- Appendix E: Wholesale gas market and pipeline framework design options;
- Appendix F: Monitoring growth in trading liquidity; and
- Appendix G: Auction design.

A separate report on information and the Bulletin Board accompanies this Final Report and can be found on the AEMC's website.

In addition, in response to stakeholders' desire to better understand the potential benefits and costs of the AEMC's proposed package of reforms, the Commission engaged PwC to undertake a cost-benefit analysis of the reform package recommended in the Draft Stage 2 Report. This work establishes a high level estimate of the broader economic benefits and the potential costs of implementing the reform package. The findings are summarised in the next chapter and set out in detail in a separate report also available on the AEMC's website.[66]

66 PwC, *Cost benefit analysis of gas market reforms Final report*, May 2016.

2 A roadmap for market development

Box 2.1 Summary of chapter

In order to achieve the Energy Council's Vision of a liquid wholesale trading market, the Commission has developed a roadmap for market development.

Trading of gas should be concentrated at two facilitated markets, at a Northern Hub at the existing GSH at Wallumbilla and at a Southern Hub on the Victorian Declared Transmission System (DTS), with improved and more unified market designs at each location.

To support wholesale market liquidity, it is vital that market participants are able to access transportation capacity to move gas to and from, and between, trading hubs. Consequently, a key element of the roadmap is the progression of reforms that will better facilitate the trading of transportation capacity, to allow capacity rights to be reallocated to those that value them most highly.

The development of liquidity in both the wholesale gas and transportation capacity markets is dependent on market participants' decisions being made on the basis of relevant and readily available information. Consequently, the Commission has developed a comprehensive package of recommendations to enhance the breadth and accuracy of information provided to the market through the Natural Gas Services Bulletin Board.

Analysis of the likely costs and benefits of the roadmap of reforms has been undertaken by PwC for the Commission. This work concluded that there are likely to be significant net economic benefits from their implementation.

2.1 A package of recommendations to achieve the Vision

As discussed in section 1.2, achieving the Energy Council's Vision of a liquid wholesale gas market will lead to lower barriers to entry, promote competition and increase efficiency. Liquidity is not an end in itself, but rather a means of allowing participants and users greater flexibility in trading and procurement, and allowing the development of risk management products.

Liquid trading markets drive the efficient allocation of gas and act as a credible alternative source of supply to bilateral contracts, contributing to competitive tension in bilateral contract negotiations. Liquid and transparent markets are also fundamental to consumers being able to know whether the price of gas reflects underlying demand and supply conditions.

In order to achieve the Vision, the Commission has developed a set of inter-related recommendations relating to **wholesale gas trading markets**, **pipeline capacity** and **information** that mutually reinforce the objectives of each another. This recognises that developing liquid trading requires not just appropriately structured trading markets, but also the ability to readily move gas between trading locations through the trading of pipeline capacity rights. In turn, liquidity in both wholesale gas and transportation capacity markets is dependent on market participants' decisions being based on relevant and readily available information.

2.1.1 Wholesale gas trading markets

The Commission considers that at the core of any roadmap for the future development of the market should be the concept that trading should be conducted in as few locations as possible so as to concentrate what liquidity there is on the east coast. However, the geography of, and range of conditions applying across, the east coast of Australia mean that it may not be possible to concentrate trading in one location or for a single reference price to be meaningful.

Consequently, the Commission recommends that two reference prices - and so two trading hubs - are likely to best strike a balance between the benefits of concentrating trading and having prices that are meaningful. Trade would be focussed at two points - in the north by continuing to evolve the existing Wallumbilla GSH as a physical hub and in the south by reforming the Victorian DWGM virtual hub. Box 2.2 provides an overview of physical and virtual hubs.

Box 2.2 Physical and virtual hubs

A gas hub is a location where the transfer of ownership and pricing of physical gas place. Two broad approaches to defining hubs can be identified.

Physical hubs are specific geographical points in the gas pipeline network, such as Wallumbilla (or Henry Hub in the USA). In order to trade gas at a physical hub, shippers must have the rights to transport gas between the hub and points of production and demand. The efficiency of gas commodity trading at the hub will therefore depend in the extent to which capacity rights are available (or can be reallocated) to market participants wishing to trade.

Virtual hubs typically encompass a large segment, or all, of a pipeline system, such as the DTS (or the British or Dutch transmission systems). They therefore allow for title transfer of gas anywhere within the definition of the hub, with a single price for all trades of gas within the area. Virtual hubs have the advantage of pooling liquidity, as all potential market participants across the pipeline system can trade at a single notional point. However, they also tend to entrench the monopoly status of the operator providing the pipeline system that forms the hub, which can lead to efficiency concerns.

A more detailed explanation and assessment of these two approaches can be found in Appendix E.

Price discovery at both markets would occur via exchange-based trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. The markets should be designed in a manner that aids trading liquidity, allows for the development of an effective financial derivative market for gas and keeps transaction costs low.

The resulting two prices would seek to reflect market conditions in the two regions which have both significant sources of supply and demand:

- In Queensland, demand is primarily driven by LNG production and large users (including gas-fired generation) and there is significant conventional and unconventional gas production.

- In Victoria, gas is primarily consumed by residential customers, and so is driven by day-to-day weather and the seasons. There is also significant production from the Bass Strait, with the Gippsland Basin in particular emerging as the "swing" producer of gas for most domestic demand.

Trading at Wallumbilla has been hampered to date by physical constraints within the infrastructure at the hub, which means that gas cannot always flow completely freely, and which has required that trade be split across three points. AEMO has been undertaking a work program to progress this issue, which has led the Energy Council to approve the implementation of the "Optional Hub Services" arrangements. These aim to promote and facilitate the trading of hub services (primarily compression) to allow participants to access a single pricing point at Wallumbilla, and the Commission considers this would form an appropriate basis on which to initially develop the Northern Hub.

In the south, the DWGM provides an opportunity to augment the existing virtual hub arrangements that span the Victorian DTS. The DWGM currently exhibits characteristics that limit the uptake of financial products that would allow participants to hedge the risks of having to purchase gas on the spot market and that would provide longer term price signals. In particular, the intra-day rescheduling process means that participants can be exposed to a number of different prices across their daily volumes. The DWGM also does not effectively support market-led investment in pipeline capacity, which leads to risks around the efficiency and timeliness of investments.

The Commission considers that these issues can be addressed by:

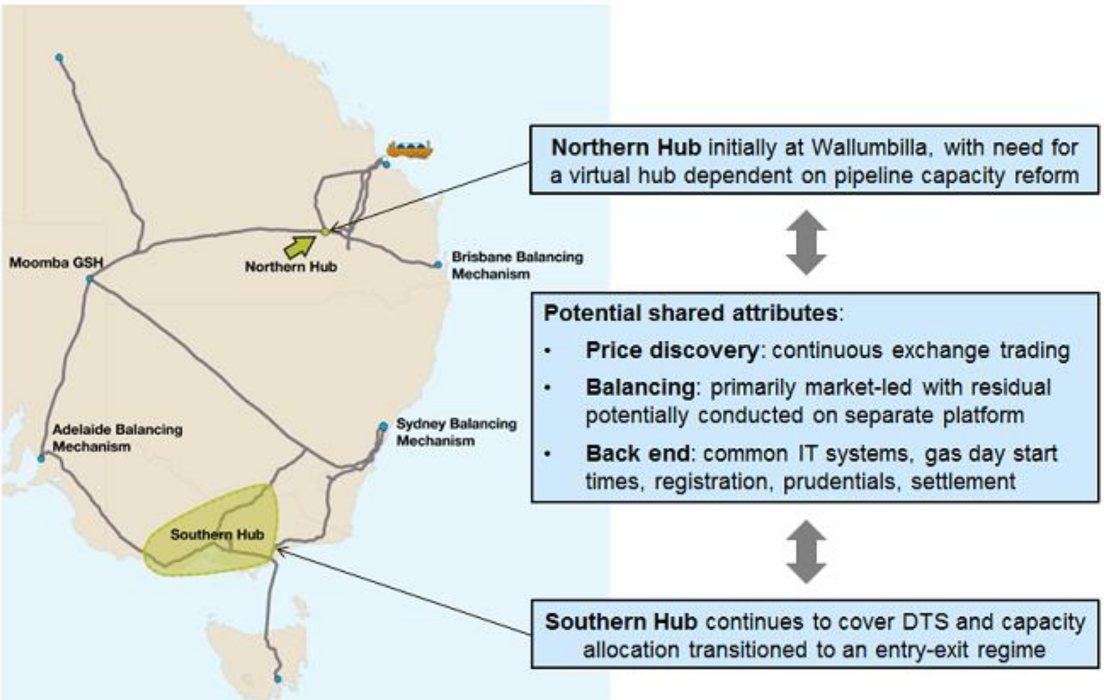
- providing additional trading options for market participants through a 'voluntary trading with market-based balancing' approach. This would include the introduction of a trading exchange similar to that in operation at the Wallumbilla GSH, providing a low cost, anonymous and transparent way for participants to trade. The exchange operator would report prices that could be used as a reference for financial derivative products. Participants would also be able to trade bilaterally at the hub, with a residual balancing role to maintain security of supply to consumers and provide certainty to traders; and

- introduce a system of firm capacity rights to replace the existing system of limited transportation rights in the market carriage arrangements. The Commission considers that the most effective model for the allocation of rights is a European style entry-exit model which would retain the general benefit of a virtual hub by pooling liquidity, but would provide improved investment signals as compared to the current arrangements and more effectively support forward trading.

The Commission considers that this overall approach to wholesale gas market development would promote the NGO by supporting efficient consumption and production decisions through establishment of a meaningful reference price at each hub. It would also provide longer term signals for efficient investment in production capability, pipeline infrastructure and services supporting trading at the hub while maintaining system security. Once liquidity has developed at the Northern and Southern Hubs, and in pipeline capacity trading, the STTMs can be simplified to a balancing role, which is expected to promote productive efficiency through lower transaction costs, while preserving competitive, market-based balancing.

The Commission's recommended number and type of gas markets on the east coast to achieve the Vision is illustrated in Figure 2.1.

Figure 2.1 Trading concentrated at a northern and southern hub



Relative to the status quo, this model will pool trading liquidity at two geographically defined locations on the east coast to produce a reference price for gas. It will reduce transaction costs and complexity by reducing the number of market designs on the east coast, lower barriers to entry and support greater market participation by physical and financial players. By getting the characteristics of the physical trading markets right, this will provide a basis for the development of financial risk management products by industry, if required.

Recommendation 1: *Focus development efforts on two primary trading hubs - a Northern and Southern hub - that share common trading arrangements to improve price discovery and reduce barriers in participation.*

Recommendation 2: *The Northern Hub to be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of Optional Hub Services.*

Recommendation 3: *The Southern Hub to be transitioned from the existing DWGM design to continuous exchange-based trading, supported by a system of firm capacity rights.*

Recommendation 4: *Simplification of STTM hubs to balancing mechanisms following the development of the Northern and Southern hubs, and pipeline capacity trading.*

2.1.2 Pipeline capacity arrangements

The establishment of a meaningful reference price for gas to support efficient consumption and production decisions depends on ready access to competitively priced pipeline capacity. Absent this, liquidity at the hubs will be restricted, impacting the reliability of the price signals provided by the trading markets.

While the current pipeline capacity arrangements have supported substantial investment in pipelines, it is not clear that they allow for capacity rights to be easily traded between users. Constraints on reallocating transportation capacity rights through the market to those that value their use most highly is likely to represent a major barrier to the development of liquid trading markets with prices that can respond to short-term shifts in supply and demand. If traders are purchasing gas to supplement their bilateral contracts on a day-ahead, week-ahead and/or month-ahead basis, then matching pipeline and hub services needs to be available at a competitive price to support trading liquidity.

Consequently, the Commission is making a number of recommendations to improve pipeline capacity arrangements to allow market participants more flexible access to transportation capacity to and from, and between, hubs. These are as follows:

Recommendation 5: *Development and introduction of a daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services which happens shortly after nomination cut-off time. This auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in-kind, offer at least all contracted but un-nominated capacity, and accommodate nominations or renominations by incumbent shippers after the auction is conducted.*

Recommendation 6: *Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services, which where possible and appropriate apply across the eastern Australian gas market. Standards to be developed are for key operational, prudential and other contractual provisions in GTAs, CTAs and Operational GTAs, and provisions in contracts used for exchange based trading on the capacity trading platform. Counterparties to existing contracts should not be materially disadvantaged through the standardisation process.*

Recommendation 7: *Creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms. Trades carried out through the capacity trading platform to be given effect through an operational transfer. For other secondary capacity trades, bare transfers will be allowed but the seller will be required to offer the buyer the option to use an operational transfer.*

Recommendation 8: *Publication of information on all secondary trades of pipeline capacity and hub services. The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties, and should occur at or shortly after the time the transaction is entered into.*

Auctions for contracted but un-nominated capacity will provide non-discriminatory access at a market-based price and improve shipper's incentives to sell capacity to the party that values it most highly. The Commission notes that this form of capacity release mechanism is not expected to undermine incentives for investment in pipelines due to the very short term nature of the capacity products being offered for sale.

Capacity trading platforms and standardised capacity products will reduce search and transaction costs and facilitate improved capacity trading liquidity. The requirement for information on secondary capacity trades to be published – including the price – will aid the price discovery process and reduce barriers to entry by lowering transaction costs and providing shippers with confidence that access is being provided on a non-discriminatory basis.

In turn, improvements in access to pipeline capacity should improve the liquidity of trading at hubs, the reliability of hub prices, and in turn provide better signals for pipeline investment, and gas consumption and production – hence promoting the achievement of the Vision and the NGO.

An example setting out how participants could buy and sell gas across the east coast market under the Commission's recommended wholesale gas and pipeline capacity trading arrangements is set out in Box 2.3.

Box 2.3 Trading gas across the east coast market

A small retailer is supplying residential customers in Melbourne and Sydney. Expected monthly load for the retailer during winter is around 13 TJ/day in Melbourne and 2 TJ/day in Sydney.

The retailer's gas supply portfolio is a combination of a 7 TJ/day GSA at Longford and gas sourced through exchange-based trading at the Southern and Northern hubs, with complementary capacity rights.

Each day the retailer nominates for its producer to inject 7 TJ of gas at the Longford injection point to the Victorian DTS. To supplement its GSA, the retailer purchases an 8 TJ/day month-ahead product on the Southern Hub exchange, with 6 TJ used to supply the retailer's Melbourne customers and 2 TJ used to supply the retailer’s Sydney customers.

The retailer has purchased firm entry rights at the Longford entry point to the DTS and each day, prior to the gas day, notifies AEMO through the nomination process that it will be injecting 7 TJ at that entry point. No entry nominations are required for the additional 8TJ of gas purchased at the Southern hub. The retailer has automatically been allocated firm exit capacity to withdraw gas from the Victorian DTS in line with its customer numbers.

The remaining 2 TJ of gas purchased on the Southern Hub exchange is shipped north from the DTS via the Culcairn exit point and along the Moomba to Sydney Pipeline to supply the retailer's Sydney customers.

To do this, the retailer has purchased a month-ahead firm exit capacity product at Culcairn on the Southern Hub exchange. Each day, prior to the gas day, it notifies AEMO through the nomination process that it will be withdrawing 2 TJ at the Culcairn exit point. The retailer utilises an existing contract for capacity on the Moomba to Sydney Pipeline to ship the gas to Sydney.

On a colder than usual winter day, the retailer expects its demand in Sydney to be 1 TJ greater than usual. The retailer purchases a 1 TJ day-ahead product from the Northern Hub exchange. In order to move the gas to Sydney, it also purchases a 1 TJ bundled capacity product from the Wallumbilla hub, from another participant offering it for sale on the secondary capacity market.

The retailer is able to undertake all of the trades at the Northern and Southern hubs, and Moomba, on the existing GSH trading platform. This is illustrated below, with the different types of products located along the top of the screen and the tenures located down the left of the screen.

Figure 2.2 Stylised trading platform

Tenure	COMMODITY												CAPACITY						
	Northern Hub				Southern Hub				Moomba				NH_SYD BUNDLED				NH_SH BUNDLED	NH_BRS	Hub service
	Qty	Bid	Off	Qty	Qty	Bid	Off	Qty	Qty	Bid	Off	Qty	Qty	Bid	Off	Qty	*[EXAMPLES OF OTHER POSSIBLE CAPACITY PRODUCTS]*		
Balance of day	5	4.00	4.75	10	10	7.20	7.80	2											
	5	4.50	4.90	5															
Day-ahead	1	5.50	6.20	2					10	6.50	6.75	5	1	1.50	1.20	1			
			5.00	1															
Week-ahead					5	6.00	6.80	15											
					5	6.50													
Month-ahead	2	5.00			1	6.00	6.80	15					5	1.00	1.50	5			
													1	1.50					
Winter16									5	5.00	6.75	5							
											6.50	5							
Q416																			

2.1.3 Information to support the market

The wholesale gas and pipeline market developments should be underpinned by arrangements to allow participants ready access to the information they require to make informed decisions.

To address current informational gaps and asymmetries identified through the review, the Commission has developed a detailed package of recommendations to improve the operation and relevance of the Bulletin Board for participants in the east coast gas market. As set out in out in a supplementary report, the package comprises improvements in the following areas:

- broadening the stated purpose of the Bulletin Board;
- improving the reporting framework, to allow all relevant facilities to report and simplifying the registration provisions;
- strengthening the compliance framework;
- expanding the coverage of the Bulletin Board to include additional information on reserves, compression and large users;
- exempt facilities that are not connected to the east coast market from registration and reporting;
- improve existing reporting requirements, including by increasing the frequency with which some information is reported;
- facilitating the publication of information on a disaggregated, as well as aggregated, basis;
- improving the information on market pricing and adding links to other useful information;
- removing pipeline operator cost recovery provisions from the NGR;
- removing the cost recovery provisions for AEMO's Bulletin Board activities from the NGR; and
- introducing a biennial process for AEMO to report on the operation of the Bulletin Board and any required changes.

Recommendation 9: *Improvements should be made to the Natural Gas Services Bulletin Board to enhance the breadth and accuracy of information provided to the market, as detailed in recommendations A-K of the East Coast Wholesale Gas Market and Pipeline Frameworks Review Stage Final Report: Information Provision.*

Enhancements to the scope, accuracy and timeliness of information are expected to promote allocative efficiency by allowing trading decisions to be based on more complete, accurate and timely information. Better decision making and greater participation on trading markets is likely to lead to more meaningful and robust market prices, which should in turn provide participants with transparent signals for investment in gas infrastructure, promoting dynamic efficiency.

2.2 Assessing the benefits of reform

In order to assess the costs and benefits of the proposed package of reforms, the AEMC engaged PricewaterhouseCoopers Australia (PwC) to undertake a high level estimate of the broader economic benefits and the potential costs of implementing the reforms.

Specifically, PwC was tasked by the AEMC to develop a robust analytical framework to assess the expected benefits and costs associated with the recommendations for an inter-related reform package relating to wholesale gas trading markets, pipeline access and information provision.

PwC's analysis estimates that by 2040, the impact on GDP of the AEMC's draft recommended package of reforms would be between 0.01 per cent and 0.10 per cent higher than the base case. This equates to an annual increase in GDP of between $0.50 billion to $3.33 billion by 2040, even once implementation costs have been considered. The most important contributor to this was the productivity effect, which is explained further in Box 2.4. The estimated gains from the reforms are pervasive and wide-spread across the eastern Australia.

Table 2.1 PwC's estimated impacts of the reforms on GDP ($bn and % deviation from baseline)

	2020		2030		2040		Present value
	%	$bn	%	$bn	%	$bn	$bn
Low scenario	0.01%	0.10	0.01%	0.37	0.01%	0.50	2.88
Central scenario	0.02%	0.49	0.04%	1.08	0.04%	1.51	8.72
High scenario	0.05%	0.98	0.09%	2.41	0.10%	3.33	19.3

Note: Results show deviation from baseline, including the impact on all states and territories. Values are $2015-16. Present values are calculated using a real discount rate of 7 per cent. Source: PwC analysis

PwC estimate that these net benefits can be realised through one-off implementation costs of between $77 million and $216 million and ongoing annual costs of between $10 million and $35 million. This equates to a net present value cost of $272 million (to 2040).

Table 2.2 PwC's estimated total costs ($m 2015-16)

	One-off implementation costs	Ongoing annual costs	Total costs over 10 years (discounted)	Total costs to 2040 (discounted)
	$m	$m	$m	$m
Low scenario	77.0	9.5	103.9	146.2
Central scenario	133.0	18.1	191.0	271.6
High scenario	215.6	35.4	335.8	493.2

Note: Totals are subject to rounding. L = Low, H = High, C = Central. Discounted costs are calculated using a real discount rate of 7 per cent. Source: PwC analysis

While the analysis is at a necessarily high level, given the nature of the benefits and costs and the stage of development of the package of reforms, the analysis shows that significant benefits from implementing these reforms can be derived from a relatively modest investment. In time, should the reforms progress, further work can be undertaken to build on the quantitative analysis undertaken by PwC to refine the benefit and cost estimates.

The PwC report setting out its cost benefit analysis of the AEMC's gas market reforms accompanies this Final Report and can be found on the AEMC's website, while the approach taken by PwC to its cost-benefit analysis is summarised in Box 2.4.

Box 2.4 Approach to the cost-benefit analysis

The cost-benefit analysis conducted by PwC reflects a package of reform where the benefits are likely to be widespread across the economy and the costs are borne by market participants and the market operator. Accordingly, PwC's approach estimates the net economic benefits once the reforms are implemented, and for reference, provides an estimate of the investment required by stakeholders to implement the reforms.[67]

The costs involved in conducting the reforms were analysed through a bottom-up approach informed by publicly available data and stakeholder consultations. Industry submissions were analysed to inform PwC's understanding of the types of costs expected to be borne by industry and the market operator. Based on these submissions, a targeted consultation was undertaken by PwC to test assumptions and workshop some plausible cost estimates that would be reflective of the costs industry would be likely to face. These include planning costs, upfront implementation costs and ongoing annual costs based on increased effort required to interact with new processes and systems.

These investments are expected to directly benefit a range of gas-using industries that are active in wholesale gas markets. In turn, this will support industries that trade with gas-using industries, and will ultimately flow through to higher employment, household incomes and government tax receipts (the indirect economic impacts).

Reflecting these flow-on effects, PwC's approach used in the analysis was to quantify both the direct and indirect economic impacts through an economy-wide, general equilibrium analysis. This involves quantifying the impact of the reforms on macroeconomic variables such as gross domestic product (GDP), employment and household consumption through a computable general equilibrium (CGE) model. CGE modelling is the standard approach used to understand the macroeconomic (direct and indirect) impacts of a change in economic policy settings.[68] It is commonly used by policy agencies when

67 To be clear, the costs and benefits are not directly comparable: the benefits calculated by PwC are the direct and indirect benefits of the reforms across the economy, net of the likely costs, while the costs calculated are only the direct investment and operational costs to implement the reforms.

68 This is because it takes into account the direct effects of the reforms and the associated responses of market participants, producers, households and financial markets.

undertaking tasks such as these, for example by the Industry Commission when assessing the Hilmer reforms.[69]

The economic impacts of the reforms are quantified by comparing a base case – that is projections under the status quo – with a policy case that includes the reforms.

The base case includes assumptions about structural changes in the gas market, including the likely path of projected gas production, LNG exports and domestic use of gas reflected in the Australian Energy Market Operator's (AEMO) forecasts.

The policy case simulates the economy with 'shocks' to the base case to represent the direct impacts of the reforms of gas market participants. The shocks were developed from theoretical analysis and conservative estimates from empirical literature on similar reforms, which were then refined with contextual information on the East Coast gas market and consideration of the likely timing of such impacts.

PwC modelled three phases of benefits:

- an immediate trading effect taking place from 2020 once the reforms come into effect, reflecting improved allocative efficiency in the wholesale gas market;
- a productivity effect that begins to take effect immediately and ramps up over the medium term, reflecting lower transaction costs for trading and improved risk management options for market participants; and
- long term investment effect, reflecting improved information transparency and gas prices leading to better informed decisions on future pipeline investments.

Sensitivity analysis was conducted on both the direct costs and net benefits of reforms.

69 See: Industry Commission, *The Growth and Revenue Implications of Hilmer and Related Reforms*, March 1995.

3 Implementing the reform package

Box 3.1 Recommendations and summary of chapter

Recommendation 10: *COAG Energy Council to establish, through an inter-governmental agreement, a dedicated Gas Reform Group (GRG) with a full-time project management office tasked with developing the package of changes to the NGL, NGR and any subordinate instruments to implement the Commission's recommended wholesale gas and pipeline capacity market reforms (Recommendations 1-8). The GRG should take into account any preferred and suggested design elements outlined by the Commission.*

The GRG should contain senior individuals from of industry, governments and consumer representative organisations and should provide advice and recommendations to governments and market institutions as to the necessary NGL and NGR changes to progress the reforms. The design of the GRG and its relationship with existing governance arrangements in the industry should provide a balance between industry involvement and policy and regulatory oversight.

Recommendation 11: *COAG Energy Council to progress an amendment to s74(1)(a) of the NGL to give the AEMC a rule making power with regard to the regulation of pipeline capacity trading arrangements.*

Regardless of the detailed design of the reforms, the Commission will require Rule changing powers in regard to the pipeline capacity trading arrangements. Such powers are not currently conferred by the NGL.

Recommendation 12: *COAG Energy Council to task the Commission with providing a biennial report on growth in liquidity in wholesale gas and pipeline capacity trading markets, with the first report due by July 2018.*

This process will allow decisions to be made on the need and timing of later reforms, such as the expansion of the geographic scope of the Northern Hub at Wallumbilla.

Recommendation 13: *COAG Energy Council to make the necessary amendments to the NGL and Regulations to add new reporting entities to the Bulletin Board framework.*

Recommendation 14: *COAG Energy Council to propose to the Commission changes to the NGR that, among other things, establish a new reporting model and reporting standard, and a new registration framework for the Bulletin Board.*

Recommendation 15: *COAG Energy Council to request that AEMO immediately progress the Commission's recommended Bulletin Board improvements that do not require changes to the NGL, Regulations or NGR.*

Reforms to the Bulletin Board have been extensively developed and consulted upon. The majority can be progressed through the standard rule change process, with the COAG Energy Council providing rule change proposals to the AEMC. In a number of cases, the Council should progress changes to the NGL and/or Regulations in order for rule changes to then be progressed. Details on the required changes to the NGL and NGR are provided in the separate report relating to information. The report also identifies a number of improvements that can be immediately progressed by AEMO that do not require changes to the NGL, Regulations or NGR.

3.1 Implementing pipeline and wholesale market reforms

The analysis undertaken by the Commission in a review is typically broad in nature and is often intended to assist the COAG Energy Council in the design of a policy approach. In this review, the Commission has assessed a range of options for wholesale market and capacity trading reforms, and has identified the package of reforms which it considers best promotes the Energy Council's Vision and the NGO. Consistent with most reviews undertaken by the Commission, this review has not considered all design details that will have to be finalised prior to implementing the wholesale market and capacity trading reforms.

Typically after a review, the COAG Energy Council develops and submits rule change requests to the Commission to take forward the recommended policy approach. The AEMC is then required to follow a consultative rule change process under the NGL to determine the necessary details for implementation, providing further opportunity for stakeholder engagement.

Implementing the suite of reforms required to meet the Energy Council Vision is a significant undertaking given the breadth and scale of changes that will be necessary over the next decade. The reforms require changes to law, regulation, rules and industry practises and procedures and must be thoroughly assessed and appropriately sequenced. This will require full-time and dedicated resourcing as well as a significant commitment from industry and relevant institutions.

The Commission therefore considers that more direct industry and consumer involvement is required before moving to the rule change process in the areas of wholesale market design and pipeline access arrangements because:

- Many of the reforms are designed to facilitate more efficient commercial transactions of gas and transportation capacity between members of industry. While the ultimate aim of the reforms is the long term interests of consumers of gas (ie, the NGO), this is likely to be achieved where the reforms help industry to make more efficient commercial transactions, the benefits of which will ultimately flow to consumers.

- As the specific design of some of the reforms is likely to be relatively broad in scope and complex, only industry participants have the requisite knowledge to develop proportionate and effective implementation arrangements that will deliver the outcomes required to meet the Vision in the least cost manner.

Nevertheless, a substantial degree of policy and regulatory involvement is required through the reform process to ensure that the private interests of industry do not supersede the long-term interests of consumers and that the detail of what gets implemented is consistent with the achievement of the Energy Council's Vision. Indeed, the existing reform process, through rule changes made with regard to the NGO, provides such safeguards.

3.1.1 A Gas Reform Group should be created to develop and facilitate reforms

Recommendation 10: *COAG Energy Council to establish, through an inter-governmental agreement, a dedicated Gas Reform Group (GRG) with a full-time project management office tasked with developing the package of changes to the NGL, NGR and any subordinate instruments to implement the Commission's recommended wholesale gas and pipeline capacity market reforms (Recommendations 1-8). The GRG should take into account any preferred and suggested design elements outlined by the Commission.*

The GRG should have a high proportion of senior industry and consumer group membership. This should provide a balance between industry involvement and policy and regulatory oversight – the GRG should be better placed than either governments or market institutions to develop the detail of the reforms, while governments and market institutions retain decision making to ensure reforms are progressed through NGL and NGR changes in the long-term interests of consumers.

The GRG and its project management office would provide the required dedication and leadership to manage the implementation process and risks, given the scope and complexity of the reforms.

A similar approach was successfully used for the development of the National Electricity Market (NEM) in the 1990s, when the National Grid Management Council (NGMC) was established by COAG to progress the reforms. The NGMC was led by an independent Chair, John Landels, and consisted of senior executives from industry and government officials. Much of the detailed technical analysis was undertaken by working groups, which drew on industry and government resources.[70]

While this process was established prior to the existing energy market governance arrangements the establishment of an entity, separate from but connected to government is still relevant for today's gas reforms which will, like the introduction of the NEM, impose significant changes on industry.

Reforms should be legally binding

The Commission recommends that the reforms for both secondary capacity trading and wholesale markets should be implemented through NGL and NGR changes and, other than in a limited number of specific circumstances, be made compulsory instead of voluntary. This is because:

- Market participants may not have a strong incentive to implement the recommendations in such a way that the expected benefits are realised to the greatest extent possible. For example, a pipeline owner may implement an auction for contracted but un-nominated capacity, but choose not to release all of that capacity in the auction, or choose to set a reserve price such that some shippers would not be able to access it despite valuing it greater than the cost of

70 *National Electricity Market: A case study in successful economic reform*, KPMG, p. 22.

its provision. These choices would have the effect of limiting access to the pipeline, and so lessen the effectiveness of the auction.

- Industry members may be unable to agree amongst themselves on the appropriate means to implement the recommendations. For example, pipeline owners (collectively) may be unable to agree with shippers (collectively) on appropriate capacity standards. Alternatively, pipeline owners may not be able to agree amongst themselves about how to hold one single auction across all pipelines on the east coast, and so implement individual auctions for each pipeline owner (despite the former potentially being more appropriate).

- Individual industry participants are unable to compel other participants to comply with the recommendations. For example, capacity standardisation could at most remain voluntary under an industry-led approach even if it was preferable for some aspects of standardisation to be compulsory.

- Preferable elements of a number of the recommendations may be contrary to existing legislation, regulation or contracts. Industry acting alone would be unable to fully implement these recommendations.[71]

- The threat of regulation is unlikely to sufficiently address these issues, or to ensure that these issues do not arise in time, were the currently regulatory interest in the sector to lessen.

The current governance structure for the sector (the NGL, NGR and any instruments subordinate to the NGL and NGR) is the appropriate means through which the reforms should be codified and made compulsory. As such, the GRG should be tasked with *recommending* changes to the COAG Energy Council (for NGL changes), AEMC (for NGR changes) and the body or bodies it recommends are delegated decision making for any subordinate instruments under the NGL or NGR. The COAG Energy Council, AEMC and any other bodies delegated responsibilities should then work, in close communication with one another, to implement any NGL and NGR changes and introduce subordinate instruments, taking into account of the recommendations of the GRG.

Pipeline owners advocated that the GRG or a similar body should determine voluntary standards with regard to the secondary capacity trading reforms, which would not be legally binding on market participants.[72] The threat of regulation, as opposed to regulation itself, would under such an approach be the catalyst for beneficial change. While such an approach may result in changes being implemented relatively quickly

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71 For example the requirement for parties to publish information on secondary trades would be likely to be contrary to confidentiality provisions in currents GTAs and contrary to s. 321 of the NGL which protects certain pre-existing contractual rights. Furthermore, standardisation of key primary and secondary contractual terms may require authorisation by the ACCC under Part IIIA of the *Competition and Consumer Act 2010* or else be contrary to the cartel provisions under s. 44ZZRM of that Act.

72 See, for example submissions on Pipeline Access Discussion Paper: APGA, APA, Jemena, Epic Energy.

by avoiding the regulatory reform process, it risks those changes being inconsistent with the policy intent, for the reasons outlined above. Indeed, the reform process may take longer overall were regulatory changes subsequently needed to meet the original policy intent.

Scope and requirements of the GRG

A single body, rather than multiple bodies, should be tasked with designing the detail of reforms for both the gas wholesale and secondary capacity trading markets. A single body will be better able to understand the interlinkages between the reforms and enable the package as a whole to be developed in an internally consistent manner.

As part of this review, the Commission has identified various outcomes that might be pursued for each of the components of the package of reforms. Where the Commission has confirmed that a particular outcome is necessary this has been reflected in formal recommendations and the GRG should be required by the COAG Energy Council to further develop the package of regulatory changes which delivers it. In other cases, GRG is better placed to consider the specific details of the reforms, given the expertise of its members:

- In some of these cases, the Commission has highlighted its **preferred** outcome which the Commission recommends the GRG should pursue unless it is clear that there are greater benefits in alternative approaches. The GRG should be required to have a strong rationale to depart from implementing a preferred outcome.
- In other cases the Commission has **suggested** the most appropriate outcome given the in-principle benefits that may arise from its implementation, which the GRG should consider in its analysis.

"Required", "preferred" and "suggested" outcomes have been identified in chapter 5 of this report for capacity trading reforms. The Commission expects that it will use a similar framework when outlining how the GRG should develop the reforms relating to the Victorian wholesale market. This will be outlined in the Commission's forthcoming Draft Final Report for the Review of the Victorian DWGM.[73]

Design and governance of the Gas Reform Group

Typically, an organisation like the GRG would be created through an inter-governmental agreement.[74] This is discussed further in Box 3.2.

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73 On 13 May 2016, the Victorian Government requested the AEMC undertake additional consultation and analysis on the Southern Hub design. This additional work is to be undertaken, and the review completed by, 14 October 2016. Victorian Government, *Response to the Draft Review of the Victorian Declared Wholesale Market*, 13 May 2016, available at: http://www.aemc.gov.au

74 For example, the *Electricity Generation and Transmission Interstate Co-operation Heads of Agreement* (30/07/1991) established the NGMC. Another example is the *Intergovernmental Agreement on a National Water Initiative* (25/07/2004) which among other things established the National Water

Box 3.2 An inter-governmental agreement to create the GRG

An inter-governmental agreement appears an appropriate approach to create the GRG, providing it sufficient mandate to undertake its responsibilities. Were the GRG to be established under an inter-governmental agreement, such an agreement might address the following matters, among others:

- mandate for GRG and scope of work;
- tenure of GRG and timelines for delivery of reforms;
- membership and composition of GRG;
- membership appointment process;
- recommendation making process of GRG;
- chair, project manager and staff arrangements;
- working group arrangements;
- funding arrangements and budget;
- indemnity of members of the GRG and its staff; and
- confidentiality arrangements.

The appropriate design of these features is discussed throughout the rest of this section.

In order for the GRG to begin developing the reforms as soon as possible, the Commission recommends that the COAG Energy Council creates the GRG by the time of the last COAG Energy Council meeting of 2016. To facilitate this, the Commission has provided a level of detail on what an agreement should contain which should allow a relatively short establishment timeline.

The COAG Energy Council should appoint a senior, independent Chairperson for the GRG. This person should have sufficient experience and standing in the industry to deliver an appropriate and timely package of recommended changes to the NGL and NGR (and subordinate instruments).

The other members of the GRG should be appointed by the COAG Energy Council based on the clear identification of relevant skills and experience. For example, the Commission envisages members of the GRG to be able to demonstrate the following:

- Commercial experience of competitive energy markets and gas system operations;
- Ability to be representative of a significant section of consumers or industry; and
- Understanding of the Australian regulatory environment and energy market reforms to-date.

Commission (NWC). Schedule C to the Agreement provided details on the NWC's: independence; functions and responsibilities; Chair; funding; number of members, their tenure, appointment process and required expertise; and project management office/staffing arrangements.

The COAG Energy Council should appoint senior (executive or Board level) representatives that meet the established skills requirements.

Additionally, the Chair of the COAG Energy Council’s Senior Committee of Officials (SCO) and one or two other SCO officials should be members of the GRG, as determined by the COAG Energy Council. The total number of members of the GRG should be limited to provide a balance between a small enough group to be manageable while still having sufficient coverage of the required skills and experience.

It would be important that the members of the GRG were committed to participate in a relatively long reform process, in order that the GRG maintains its institutional knowledge and the seniority of its membership.

Given the requirements for extensive, senior level industry engagement, the complexity and scope of the issues to address, the relatively long-lived nature of the reform process and the need for a broad east coast focus, the Commission does not recommend that SCO officials be required to progress the package of reforms. SCO officials are already tasked with championing both national and state-level reform processes and in most cases are supported by relatively small teams. Such an additional burden would create significant risks to the delivery and timing of the reform program.

SCO representatives will still be able to provide a central role in the GRG and provide a clear policy direction to the GRG, taking into account the views of all participating jurisdictions. This should mean that the package of changes to the NGL and NGR developed by the GRG is consistent with the policy intent. Although the recommendations of the GRG would not be binding on the COAG Energy Council or AEMC to implement through NGL and NGR changes, the Commission envisages that through the SCO representatives, the GRG's recommendations would likely be appropriate and consistent with the NGO. The GRG should also be required to report regularly to the COAG Energy Council (for example, prior to each COAG Energy Council meeting, which are typically biannual).

The GRG, including the Chairperson, would be an independent group funded by the COAG Energy Council and supported by a dedicated and full time project management office. The project manager would report to and be appointed by the Chairperson of the GRG, coordinate the design work overseen by the GRG and provide legal, economic and technical advice, both through the staff and through external consultancies or law firms. It may be appropriate for the project manager to be appointed early in the implementation of the GRG, as one of the first tasks of the newly appointed Chairperson. The project manager would work closely with the GRG and the Chairperson in particular.

The project manager would coordinate work undertaken by various Working Groups to develop the reform package. Working Groups would be comprised of members of industry, including from organisations not represented directly on the GRG, market institutions such as the AEMC, AEMO and the AER where relevant, and government officials. These groups, the GRG's staff, and external consultancies would be expected to undertake the majority of the work to develop the reforms, under the direction of the GRG and under the management of the project manager.

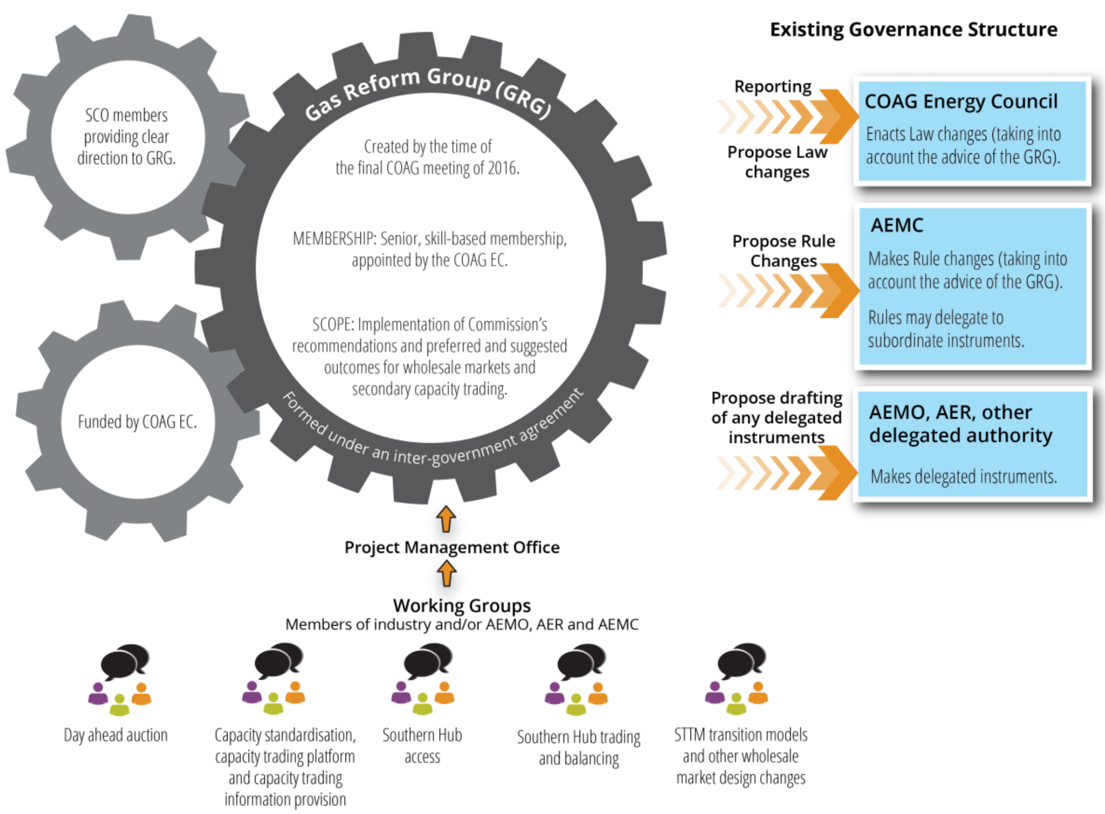
The number, membership and remit of Working Groups would be determined by the GRG in collaboration with the project manager. We expect that Working Groups might be formed in the following areas:

1. Day ahead auction design for contracted but un-nominated capacity;
2. Capacity standardisation, capacity trading platform and capacity trading information provision;
3. Southern Hub access;
4. Southern Hub trading and balancing; and
5. STTM transition models and other wholesale market design changes.

The COAG Energy Council should fund the GRG to cover salaries and other on-costs for the Chairperson and staff including the project manager; office space and related outgoings; IT costs; consultancy costs; and travel and other out-of-pocket costs for members of the GRG and Working Groups. Members of the GRG (other than the Chairperson) and Working Group members would be expected to provide their time on a voluntary basis. This cost is appropriately borne by industry given the likely importance to industry of progressing appropriate reforms.

A summary of the proposed GRG model is provided in Figure 3.1.

Figure 3.1 Summary of Gas Reform Group



3.1.2 NGL and NGR changes required to give effect to the package of reforms

The task of the GRG would be to propose the details of recommended NGL changes to the COAG Energy Council and details of recommended NGR changes to the AEMC to effect the detailed design of the recommended reform package. It would also develop a draft of any subordinate documents, such as AEMO procedures, that it recommends be created under the NGR.

The Commission has considered the changes to the NGL, NGR and subordinate instruments that may be required to implement each of the packages of the secondary capacity trading reforms. These are detailed in chapter 5. The Commission expects to take a similar approach to its recommended changes for wholesale markets in the Draft Final Report to the Review of the Victorian DWGM.

In many cases, the NGL and NGR changes and subordinate instruments required will depend on the detailed design of the reforms, which will only be known once the GRG's analysis has progressed. However, regardless of the detailed design, the Commission will require NGR making powers in regard to the regulation of pipeline capacity trading arrangements. Such powers are not currently conferred by the NGL (unlike for example the power to make rules with regard to the regulation of the operation of the DWGM).[75] The Commission therefore recommends that the COAG Energy Council progress an amendment to s74(1)(a) of the NGL to give the AEMC a rule making power with regard to the regulation of pipeline capacity trading arrangements.

Recommendation 11: *COAG Energy Council to progress an amendment to s74(1)(a) of the NGL to give the AEMC a rule making power with regard to the regulation of pipeline capacity trading arrangements.*

Further issues to be resolved by the GRG in the implementation of the package of reforms include whether:

- Schedule 1 to the NGL needs to be amended to include additional matters or things (to be specified in that Schedule 1) for which the AEMC may make Rules; and
- the AER's statutory functions and powers as set out in the NGL are sufficient for it to monitor and enforce the reforms, in particular the capacity market arrangements including the operation of the auction platform and trading platform.

In many cases, the GRG may recommend that highly detailed design is not contained in the NGR, but instead in subordinate instruments. This is a common approach taken in both the NGR and National Electricity Rules (NER). In these cases the NGR might contain overarching design features and principles, and instruct another body to be responsible for the detail through the subordinate instrument.

75 NGL, s. 74(1).

Options for subordinate instruments include, but are not limited to:

- AEMC Standards;
- AEMO Procedures;
- AER Guidelines;
- extensions of the access arrangement regime for pipeline regulation (ie, an AER approved instrument); and
- documents overseen by Committees created under the NGR. Examples in the electricity sector include the Reliability Panel[76], the Information Exchange Committee[77] and the Settlement Residue Committee[78].

3.2 Assessing the development of the reforms

An important element in determining whether the Energy Council's Vision is being achieved will be monitoring the development of liquidity in the wholesale gas and pipeline capacity trading markets. Monitoring liquidity on an ongoing basis will allow industry participants and policy makers to understand how the trading markets are performing, the value they are providing to gas market participants, and how they could be improved to better meet market participants' needs.

Accordingly, the Commission recommends that the Energy Council tasks the Commission with reporting to Energy Ministers on a biennial basis on the growth in trading liquidity in the wholesale gas and pipeline capacity trading markets.

Recommendation 12: *COAG Energy Council to task the Commission with providing a biennial report on growth in liquidity in wholesale gas and pipeline capacity trading markets, with the first report due by July 2018.*

The Commission recommends the first report be provided to the Energy Council by July 2018, and expects that report to primarily cover how trading is developing at the Wallumbilla and Moomba GSHs, as well as updating Energy Ministers on how the market is adjusting to the structural changes underway. Subsequent reports will measure the development in gas trading at the Southern hub and capacity trading, once reforms to these markets have been implemented.

Through the biennial report, the Commission will consider whether to recommend to the Energy Council that additional work to expand the geographic scope of the Wallumbilla GSH be undertaken and progressed through the GRG.

76 National Electricity Rules, s. 8.8.

77 National Electricity Rules, s. 7.2A.2.

78 National Electricity Rules, s. 3.18.5.

Similarly, the Commission proposes to advise the Energy Council through the biennial review on the appropriate time to simplify the STTM hubs, with the development of those reforms to then be progressed by the GRG.

The Commission would also use the report to recommend if a longer term use-it-or-lose-it mechanism is required to enable a more effective market for pipeline capacity trading.

In order to evaluate market liquidity a range of indicators, both quantitative and qualitative, need to be considered. The Commission recommends that the quantitative indicators developed for this report be published by the AER on a regular basis to promote market transparency.[79] Qualitative data collected through surveys of participants is useful because elements of liquidity, such as aspects related to reputation, trust and culture cannot be captured through market data. Lastly, as the relative importance of liquidity indicators will change over time as the markets mature, the reporting framework should be sufficiently flexible to incorporate new metrics into the analysis.

Further detail on this recommendation is set out in Appendix F.

3.3 Reforming the Natural Gas Services Bulletin Board

The Commission has made significant progress in analysing and consulting on the details of reform to the Natural Gas Services Bulletin Board (Bulletin Board). Given this, and the relatively low level of complexity of the Bulletin Board reforms compared to the wholesale and capacity market reforms, most of the recommended reforms can be progressed as a next stage through amendments to the NGR.

The Commission recommends that the COAG Energy Council submits a rule change request to the Commission to progress these reforms. These reforms are discussed in chapter 6, with the detail of the proposed rules to implement the Commission's recommendations provided in an accompanying *Stage 2 final report: information provision*.

Some of the reforms require changes to the NGL and/or the National Gas (SA) Regulations (Regulations) to be made prior to rule changes being made. These are to add new reporting entities to the Bulletin Board framework. These new parties are: holders of proved and probable ("2P") gas reserves; LNG facility owners; large users; and Gas Supply Hub compressor station owners. The Commission recommends that the NGL changes be pursued in parallel with the rule changes which can be progressed immediately. Again, the required NGL and Regulation changes are discussed in chapter 6 and in more detail in the accompanying *Stage 2 final report: information provision*. This also identifies a number of improvements that can be made by AEMO that do not require changes to be made to the NGL, Regulations or NGR.

79 This could be done through the AER's Industry Statistics webpage, found here: https://www.aer.gov.au/industry-information/industry-statistics

Recommendation 13: *COAG Energy Council to make the necessary amendments to the NGL and Regulations to add new reporting entities to the Bulletin Board framework.*

Recommendation 14: *COAG Energy Council to propose to the Commission changes to the NGR that, among other things, establish a new reporting model and reporting standard, and a new registration framework for the Bulletin Board.*

Recommendation 15: *COAG Energy Council to request that AEMO immediately progress the Commission's recommended Bulletin Board improvements that do not require changes to the NGL, Regulations or NGR.*

These recommendations are not contingent on the other recommendations in this report, and can be commenced immediately.

3.4 A staged approach to implementation

The need to progress the reforms in a timely manner is being driven by the pace of change in the east coast gas market. By the end of 2018, all six of the LNG export trains at Gladstone are expected to be fully operational, while one of these projects continues to source substantial volumes of gas from outside its portfolio, reducing supply that could have been directed to the domestic market.[80] Over the same period around 450 PJ of long term GSAs are rolling off, requiring domestic users to enter the market to secure new supply in an uncertain environment.[81]

While the Commission considers that many of its recommendations should be implemented as soon as possible, others will need to be implemented in sequence. In this way, the Commission envisages that the implementation of the complete package will occur over several phases, forming a roadmap to guide the development of the market over the next decade.

The Commission's current view is that the first phase of reform, to be completed within the next five years, would comprise:

- Implementing the recommended enhancements to information provided through the Bulletin Board through NGL, Regulation and NGR changes, as discussed in chapter 6.
- Creating the GRG to design and facilitate the implementation of:
  - the reforms to the DWGM discussed in chapter 4 and to be more fully developed in the Commission's forthcoming Draft Final Report for the DWGM Review; and
  - the recommended capacity trading mechanisms discussed in chapter 5.

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80 On 24 December 2015, Santos announced to the ASX that GLNG had contracted with AGL to buy 254 PJ of gas over 11 years commencing in January 2017.

81 Department of Industry, Innovation and Science, *Gas Market Report 2015*, p. 40.

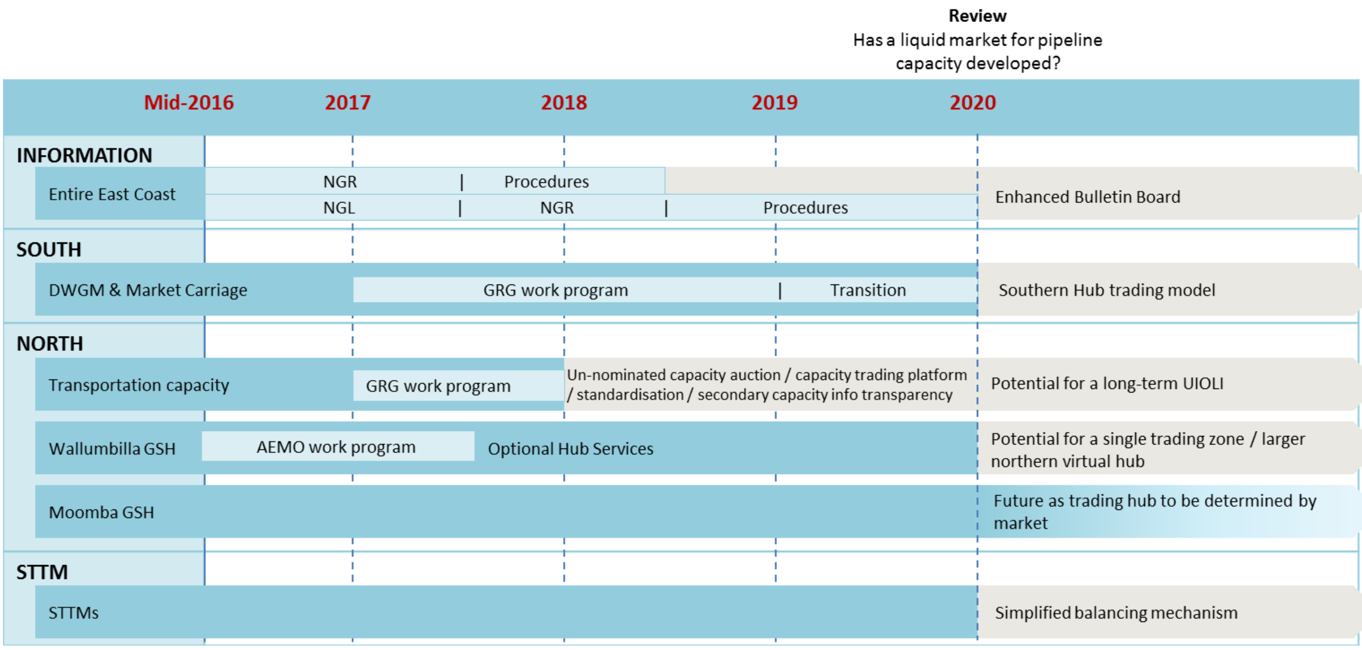
These measures would be in addition to the work currently being undertaken by AEMO to implement the Optional Hub Services arrangements at the Wallumbilla GSH.

Once the recommendations relating to the Northern and Southern hub and to pipeline capacity trading have been implemented, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. If an effective market for pipeline capacity does not develop, then the pipeline access arrangement reforms may need to be coupled with a long term use-it-or-lose-it mechanism. Additionally, the Commission would look to potentially establish a single trading zone / larger northern virtual hub, if required.

As discussed in section 3.2, the Commission should be tasked with monitoring liquidity and providing a report to the Energy Council on a biennial basis. This review will provide the mechanism through which the Commission recommends when some of the staged reforms should be implemented, with their development undertaken by the GRG.

An overview of the staging of the overall package is set out in Figure 3.2 below.

Figure 3.2 Reforming east coast gas markets



4 Wholesale gas trading markets

Box 4.1 Recommendations and summary of chapter

The Commission recommends the following roadmap for the development of wholesale gas trading markets on the east coast:

- ***Recommendation 1:*** *Focus development efforts on two primary trading hubs - a Northern and Southern hub - that share common trading arrangements to improve price discovery and reduce barriers to participation.*
- ***Recommendation 2:*** *The Northern Hub to be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of Optional Hub Services.*
- ***Recommendation 3:*** *The Southern Hub to be transitioned from the existing DWGM design to continuous exchange-based trading, supported by a system of firm capacity rights.*
- ***Recommendation 4:*** *Simplification of the Short Term Trading Market (STTM) hubs to balancing mechanisms once the recommendations related to the Northern and Southern hubs, and pipeline capacity trading, have been implemented.*

In order to have confidence that a meaningful reference price for gas will develop, the Commission has sought to concentrate trading liquidity and to set out a preferred trading approach that facilitates ease of use and understanding by participants. Given the number of participants on the east coast, the Commission sees a degree of risk in recommending the continued development of multiple hub locations and different market designs.

Exchange-based trading provides market participants with flexibility in how they buy and sell gas. A range of products from spot to month-ahead and beyond can be traded on an exchange, creating transparency around daily *and* forward price expectations. Exchange-based trading also establishes preconditions for the development of financial risk management products.

Once the recommendations relating to the Northern and Southern hubs and to pipeline capacity trading (see below) have been implemented, the Commission recommends the STTM hubs be simplified from their current design to purely support the trading of daily gas imbalances. This will reduce transaction costs for participants who have to engage with these markets on a daily basis, while still providing a transparent and competitive balancing mechanism.

4.1 Development of the east coast gas market

The east coast currently has three gas market trading designs, each developed separately of the other and at different times in the evolution of the broader east coast market. As of 1 June 2016, these are spread over six trading hub locations.[82]

The Commission considers that at the core of an east coast gas market development roadmap should be the concept that trading be conducted in as few locations as possible in order to concentrate liquidity. Accordingly, the Commission is recommending a pathway for the future development of the market that seeks to concentrate trading at two points on the east coast – in the north by continuing to evolve the existing Wallumbilla GSH and in the south by enhancing the Victorian DWGM.

Recommendation 1: *Focus development efforts on two primary trading hubs - a Northern and Southern hub - that share common trading arrangements to improve price discovery and reduce barriers to participation.*

Two primary pricing points have been recommended as the Commission is concerned that multiple trading locations will unnecessarily split liquidity and reduce the benefits to participants of a liquid wholesale market. Prices at the two hubs would seek to reflect the differing market conditions in the two regions which have significant sources of supply and demand:

- In Queensland, demand is primarily driven by LNG production and large users (including gas-fired generation) and there is significant conventional and unconventional gas production.
- In Victoria, gas is primarily consumed by residential customers and so is driven by day-to-day weather and the seasons. There is also significant production from the Bass Strait, with the Gippsland Basin in particular emerging as the "swing" producer of gas for most domestic demand.

Although there could be reasons for wanting to establish trading hubs to reflect market conditions in other areas, the Commission has concerns with approaches that seek to support the emergence of more than two reference prices, as this may serve to unnecessarily split liquidity both in short term trading and in the benefits that can be obtained from having an accepted market price to refer to in financial derivatives and in long term physical contracts.

The Commission's recommended number and type of gas markets on the east coast to achieve the Vision was illustrated in Figure 2.1 (see Chapter 2).

Further, the Commission considers that exchange-based trading provides gas market participants with greater flexibility in how they buy and sell gas than the gross pool approach of the DWGM and STTM hubs. A range of different products - from on-the-day to month-ahead and beyond - can be traded on an exchange, creating

82 AEMO expects to have implemented the Moomba GSH by 1 June 2016.

transparency around spot and forward price expectations. Exchange-based trading is also less administratively complex to implement and the Southern Hub can leverage off AEMO's systems and learnings from implementing the Wallumbilla GSH.

Further detail on exchange-based trading is provided in Box 4.2.

Box 4.2 Exchange-based trading and gas markets

Exchange-based trading involves buyers and sellers placing anonymous bids to buy gas or offers to sell gas using an electronic trading platform. The market matches bids and offers on price to execute a trade as is done on a stock market. All transactions on the trading platform are published as they occur to support liquidity and transparency.

Under the Commission’s recommended wholesale market design, participants can buy or sell gas through the exchange or trade bi-laterally outside the exchange. When a trade occurs, the facility operator is notified by the shipper and market operator, so that the existing physical nominations of the buyer and seller can be adjusted at the hub.

Trading occurs between predefined business hours on standardised, hub specific contracts. Exchange-based trading products can evolve over time to suit the requirements of participants. Some common contracts include: on-the-day; day-ahead; week-ahead; and month-ahead.

Participants will generally utilise a combination of exchange-based products, along with their bilateral contracts, in order to manage their gas portfolio needs. Continuous exchange trading facilitates the integration between the spot and forward markets through continuous trading of the forward products leading up to the gas day.

A liquid forward curve provides participants with transparency around the market's future price expectations for gas, say, a week ahead or a month ahead or even the following year. Financial derivatives to manage price risk are often developed over the most liquid of these physical products.

While not explicitly part of the Northern Hub, a second GSH at Moomba is likely to be an appropriate transitional measure to provide additional flexibility until trading at the Northern and Southern hubs, and in pipeline capacity, matures. Over time, Moomba could establish itself as a transit point for gas flowing between the east coast markets, particularly given the recent announcement to connect the Northern Territory to the east coast gas market via the Northern Gas Pipeline.[83]

Once the Northern and Southern hubs are developed and pipeline capacity trading is introduced, the Commission recommends that the STTM hubs are pared back from their current design to purely support transparent and competitive balancing. This will reduce transaction costs for participants that have to engage with these markets on a

83 See: https://jemena.com.au/industry/pipelines/northern-gas-pipeline

daily basis, while still preserving competitive, market-based balancing at the demand centres.

The Commission notes that a potential emerging issue for the east coast gas market is that of different gas specifications. The Commission understands that the LNG plants require a dryer gas specification than the Australian standard. Natural gas infrastructure operating on two different gas specifications could present a barrier to trade and the achievement of a liquid wholesale gas market. The ACCC's position, with which the Commission concurs, is that the Energy Council should monitor this issue and ensure that any costs associated with a non-standard gas specification are borne by the market participants that required that alternative specification.[84]

4.2 Northern Hub for trading gas

The Commission considers that the Energy Council's Vision would be best met by focussing trade at a Northern and Southern hub. Price discovery at both hubs would be via exchange-based continuous trading, with common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. Growth in trade and liquidity would be supported by a complementary package of pipeline access and market information reforms.

The Commission recommends that the Wallumbilla GSH be designated as the Northern Hub and that the Optional Hub Services model continue to be implemented. The Commission supports the work that AEMO has carried out in conjunction with industry as part of the design and implementation of the GSH at Wallumbilla, and considers it prudent to build on the existing GSH market design framework so that it has the best possible chance of meeting the Energy Council's Vision.

The Optional Hub Services model reduces the three pricing points at Wallumbilla to one, thereby pooling liquidity and potentially creating more trading opportunities. It will also include implementation of hub services products that will allow participants to trade compression capacity at the hub. The Commission understands that implementation of the single Wallumbilla product should occur by March 2017. An overview of the Optional Hub Services model is described in Box 4.3.

Recommendation 2: *The Northern Hub to be located at Wallumbilla, with existing physical trading limitations addressed in the first instance through implementation of Optional Hub Services.*

The majority of submissions to the Stage 2 Draft Report support AEMO's work in continuing the evolution of the Wallumbilla GSH to improve liquidity, with the AER noting that the extent to which participants respond to the Optional Hub Services arrangements will help inform policy options to further develop the market.[85] AGL and QGC were less confident that Optional Hub Services would produce the expected

84 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 15.

85 Stage 2 Draft Report Submissions: ERM Power, RWE Trading, Santos, EUAA, AEMO, APPEA, APA Group, Jemena, Esso, PIAC.

levels of trading liquidity and put forward that further steps, such as a virtual trading point around Wallumbilla, may be required.[86]

Box 4.3 Optional Hub Services model[87]

At the time of approving the implementation of the Wallumbilla GSH, the Energy Council requested AEMO undertake a review of hub services to support the transition from three trading locations to one trading location. At the December 2015 meeting, the Energy Council endorsed implementation of a single Wallumbilla product through the Optional Hub Services model.

The Optional Hub Services model consolidates the three markets at Wallumbilla into one by pooling together trading participants operating on pipelines connecting to Wallumbilla. A default location within the Wallumbilla hub for the title transfer of gas would be defined in order to establish a single pricing point.

Hub services facilitate the delivery of transactions between trading participants operating on the different pipelines around the Wallumbilla hub. In essence, they facilitate the transfer of gas within a hub. Participants would manage the hub services required to transport their gas to the default trading location by using their own hub services or by purchasing a service from another shipper through the secondary market.

The Optional Hub Services model would establish a voluntary market for the trade of hub services by utilising the existing GSH exchange, enabling participants without existing access to hub services to exchange gas between facilities at Wallumbilla. The model aims to minimise the requirements for hub services through the netting and matching of delivery positions at Wallumbilla delivery points.

In the Wholesale Gas Markets Discussion Paper, prepared as part of the development of the Stage 2 Draft Report, the Commission tested three market design concepts.[88] Two of these concepts included virtual hubs of varying sizes around Wallumbilla. One virtual hub covered Wallumbilla and the Roma to Brisbane Pipeline (RBP), while the other covered all pipelines north of Moomba, excluding the Moomba to Sydney Pipeline (MSP).

The Commission is conscious of providing the Energy Council with a solution that not only supports the Vision, but is proportionate to the issues at hand and clearly promotes the NGO. While implementing a larger virtual hub across a wider geographic footprint than the Wallumbilla facility could be expected to contribute to trading liquidity by concentrating a significant number of diverse buyers and sellers, further detailed work would need to be carried out before there was sufficient

86 Stage 2 Draft Report Submissions: AGL, QGC.

87 AEMO, *Hub Services for a Single Wallumbilla Market, Draft Report*, October 2015.

88 AEMC 2015, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, Wholesale Gas Markets Discussion Paper*, 6 August 2015, Sydney.

confidence that the costs and disruption of making such a significant change would outweigh the benefits.

Over the longer term, the Commission's view is that the Wallumbilla GSH may need to transition from a physical hub to a small virtual hub in order to promote the Energy Council's Vision. This is because the design of the GSH may impact liquidity growth in the following ways:

- Limited competition in the market for hub services to ship gas across the physical hub location.
- Lack of delivery certainty after trades have been matched on the exchange.

Limited competition in the market for hub services

The Commission understands that the primary hub services required to move gas across the Wallumbilla hub are compression and redirection. Compression allows participants to ship gas in a westerly direction from low-medium pressure headers to high pressure headers between pipelines at the hub. Compression may also be required to ship gas from the South West Queensland Pipeline (SWQP) to the Queensland Gas Pipeline (QGP), depending on operational conditions. Redirection services allow participants to ship gas in the reverse direction through displacement of gas from a high pressure header to a low-medium pressure header.

A high portion of compression services at Wallumbilla are currently contracted to three major parties. Outside of long term bilateral contracting for new capacity, options for participants to procure access to compression to support short term trading at the hub include:

- the secondary market from the three primary shippers who hold compression capacity; or
- on an as-available basis from APA Group (the facility operator of most of the infrastructure at the Wallumbilla hub).

The Commission understands that re-direction services are primarily provided by APA Group as the facility operator.

If gas market participants are unable to access contracted but unused compression capacity to facilitate trading, then liquidity growth at the hub will be restricted. The Commission recognises this and is recommending the following measures to help reduce transaction costs and promote the development of a workably competitive market for the trading of pipeline capacity *and* hub services (as set out in Chapter 5).

Lack of delivery certainty after trades have been matched on the exchange

A drawback of the GSH market design that has been put forward to the Commission is the lack of delivery certainty after a trade has taken place on the exchange.[89]If a

89 CQ Partners, *Submission to the Stage 1 Draft Report*, p. 6.

counterparty fails to deliver the agreed volume of gas, there is no market-based balancing mechanism to deliver the gas that may be essential for the buyer to operate a factory, supply retail customers or run a gas-fired generator.

Compensation is required to be paid in the event that an exchange counterparty defaults on part, or all, of its delivery quantity, outside of the 5 per cent tolerance set by AEMO. If this occurs, participants are required to compensate their counterparty for 25 per cent of the value of the variation.[90]

Lack of delivery certainty is of particular concern to participants who do not have large portfolios of gas to call on in the event that a counterparty defaults on delivery. One of the positive features of the STTM hubs and DWGM put to the Commission by stakeholders was the certainty of delivery that these markets provide once a trade has been entered into.[91]This certainty is provided by the respective balancing mechanisms.

The Commission notes AEMO can suspend market participants from the GSH if the delivery variance quantity is equal to 25 per cent or more and such an event has occurred on three or more occasions on a rolling six month period, without any reasonable explanation from the market participant.[92] However, for the Northern Hub to be an attractive market for all participants to trade at, and for trading liquidity to be maximised, the Commission considers that a market-based balancing mechanism is likely to be an aspect of the market that needs to be considered into the future.

Implementing a market-based balancing mechanism at Wallumbilla would necessitate the need for the GSH to transition from a physical to a small virtual hub, consistent in design with the Commission's recommendations for the Southern Hub. A small virtual hub could be based on the Single Trading Zone model discussed below.

4.2.1 Wallumbilla Single Trading Zone

As part of advice to the Energy Council on a single Wallumbilla product, AEMO put forward the Single Trading Zone design as a potential option. Box 4.4 provides an overview of this model, which would provide for a hub operator to manage and balance all flows at the hub, regardless of origin or destination.

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90 AEMO, *Detailed Design for a Gas Supply Hub at Wallumbilla*, 19 October 2012, p. 20.

91 CQ Partners, *Submission to the Stage 1 Draft Report*, p. 5.

92 AEMO, *Gas Supply Hub Exchange Agreement, version 3*, p. 65.

Box 4.4 Single Trading Zone model[93]

The Single Trading Zone model would group together delivery points on key facilities connecting at Wallumbilla to form a single market with all transactions and transit flows facilitated through a virtual trading point. A hub operator would manage all gas flows and balancing at the hub.

The Single Trading Zone would have a mandatory participation framework that would apply to all flows transiting the Wallumbilla hub. As such, the framework would apply to exchange transactions, bilateral and OTC market transactions and to participants transiting gas through the hub. While the framework would apply to all gas flows, trading through the exchange would remain voluntary.

The inclusion of all flows is necessary to facilitate efficient operations and delivery of transactions at the hub. It would allow the hub operator to maximise opportunities to aggregate and net flows and to optimise gas flows and balancing. If participants were able to arbitrage between their own services and a hub operator provided service then it would be difficult for the hub operator to provide a fixed price and a firm service.

The following aspects of the market framework would likely apply to all Wallumbilla transactions under a Single Trading Zone model:

- All Wallumbilla transactions would be delivered at a virtual trading point.
- A hub operator would be responsible for the delivery of all transactions.
- All Wallumbilla flows would be subject to a market balancing arrangement - participants who are out of balance would be balanced by the hub operator and subject to any market balancing charges.

Development of a small virtual hub over Wallumbilla would enhance trading liquidity by enabling traders to bring gas to or receive gas from any point within the hub definition. Beyond nominating their intended delivery/receipt locations, participants would not be involved with the operational processes of managing gas flows or having to separately procure hub services to match trades. This would simplify participation in the market.

The two issues identified under the Optional Hub Services model around certainty of delivery and access to competitively priced hub services would also be resolved. Under the Single Trading Zone model, certainty of delivery is provided through a market balancing arrangement, whereby participants who were out of balance would be balanced by the hub operator as a last resort. Standard tariffs would apply for hub services for trading gas at the hub, as well as transiting gas through the hub, mitigating the ability of parties to price hub services on an anti-competitive basis.

93 AEMO, *Hub Services for a Single Wallumbilla Market, Draft Report*, October 2015.

Over time, the outcome of a single trading zone would likely be a liquid hub where participants have confidence that the observed price reflects underlying supply and demand conditions. This would in turn encourage financial players to participate, as they will be confident that the liquidity exists to close out positions taken in the market prior to having to deliver or take delivery of gas.

Further detail of the Single Trading Zone design and analysis of the costs and benefits would need to be undertaken before a decision to implement could be considered. In particular, consideration would need to be given to the arrangements for accessing the hub by shippers and for cost recovery by the infrastructure owner. Other aspects include the governance arrangements and role of the hub operator, as well as the treatment of existing property rights in the transition to the new regime. Consultation with industry on these issues would be an essential component in finalising the design.

In the event that trading liquidity at the Northern Hub under the Optional Hub Services model does not develop in-line with the expectations of participants and policy makers, the Commission would recommend to the Energy Council that this additional work to develop the Single Trading Zone model occurs. The Commission would make this recommendation as part of its biennial review of trading liquidity in the wholesale gas and pipeline capacity trading markets, as set out in Appendix F. The Commission has recommended that the first review be provided to the Energy Council by July 2018.

4.2.2 Moomba GSH trading location

AEMO has announced that it will be implementing a GSH at Moomba by 1 June 2016 and that this will extend the GSH model implemented at Wallumbilla.[94]

As discussed above, the Commission sees a risk in spreading the limited trading on the east coast too thinly. Without most participants trading at a common location, there is unlikely to be the liquidity required to support a meaningful reference price and to provide participants with the confidence to use the markets regularly. Without confidence in the physical market, players without physical positions - such as financial institutions - are unlikely to participate due to the risk of not being able to close out their trades.[95]

In the United States, having many physical hubs across the network has been a successful model due to the large number of trading market participants - larger than any other country. Markets at individual physical hubs grow and contract in the United States depending on their level of use over time. This is unlikely to be a realistic approach in Australia, where the market is much more concentrated. If no individual trading point on the east coast emerges to become the benchmark hub, then the benefits of a liquid wholesale gas market will not flow through to consumers.

94 AEMO, *Gas Supply Hub Reference Group Paper 29, Moomba Trading Location Implementation Plan.*

95 Financial players seek to close out their trades on the physical market prior to delivery as they generally do not have the capacity to deliver or receive gas.

Nonetheless, while not explicitly part of the Northern Hub, a second GSH at Moomba is likely to be an appropriate transitional measure to provide additional flexibility until trading at the Northern and Southern hubs, and in pipeline capacity trading, matures. Over time, Moomba could establish itself as a transit point for gas flowing between the east coast markets, particularly given the recent announcement to connect the Northern Territory to the east coast gas market via the Northern Gas Pipeline.[96]

Most submissions to the Stage 2 Draft Report that discussed Moomba saw the development of the hub as an appropriate next step, with RWE Trading commenting that the Moomba GSH and STTM hubs could conceivably develop as satellite hubs, where trade prices are set as a basis to the Northern and Southern hub prices.[97]

4.3 Southern Hub for trading gas

4.3.1 Current state of the Victorian gas market

The DWGM was established in 1999 by the Victorian Government with the objective of supporting retail competition and encouraging a diversity of supply sources and upstream competition. The DWGM is generally regarded by participants as having met these objectives, providing an effective and competitive gas balancing service and facilitating trading of gas in Victoria based on short term prices.

However, the underlying DWGM design, with multiple pricing schedules, ancillary payments and uplift charges does not appear to set strong preconditions for the development of risk management products. As GSAs become less flexible and higher priced, participants have been utilising the DWGM to a greater extent for their gas purchasing needs. This has resulted in an increased exposure to spot price risk.

Also absent from the DWGM is the mechanisms necessary for market-driven investment in the pipeline system. Investment currently occurs predominately through the regulatory process where costs are recovered from consumers. This means that the risk of inefficient investment is falling on those who are not best placed to manage it – that is, consumers.

These issues, highlighted in a number of previous reviews of the Victorian gas market[98] and explained below, are amplified by the growing LNG export industry. The size of LNG demand - three times that of the domestic market - as well as the variable nature of the coal seam gas wells supplying the LNG production facilities, has resulted in changing gas flows across the system and participants managing their portfolios more actively than in the past through short term trading.

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96 See: https://jemena.com.au/industry/pipelines/northern-gas-pipeline

97 Stage 2 Draft Report Submissions: ERM Power, RWE Trading, Santos, EUAA, AEMO, APPEA.

98 For example: VENCorp, *Victorian Gas Market Pricing and Balancing Review - Recommendations to Government*, 30 June 2004; Victorian Gas Market Taskforce, *Gas market taskforce: final report and recommendations*, 2013; K Lowe Consulting, *Gas Market Scoping Study, A report for the AEMC*, July 2013.

The need for markets which can foster liquidity and support the development of risk management products presents significant opportunities for Victoria but the Commission also recognises that changes to the existing arrangements must be carefully considered.

4.3.2 The case for change in Victoria

Effective risk management in the DWGM

Efficient gas markets tend to allow participants to manage the operational risks of delivering gas safely, as well as the financial risks associated with price fluctuations. To support effective risk management, market participants need to have access to a meaningful reference price reflective of underlying supply and demand conditions, as this will aid commercial decision-making and the development of financial products.

Market participants in the DWGM are only able to hedge the short term price risk arising in the market over the longer-term by trading gas bilaterally outside of the market (generally by entering into a GSA with a producer at an injection point). Approximately 80 per cent of trading takes place outside of the market in this way, and has led to most participants aligning their bids and offers in the market to the terms of their GSA.

In a mature market, we would expect financial products to be made available so that participants can hedge the price risk of purchasing gas on a trading market. While the ASX has released a number of such products, it appears that the DWGM currently exhibits characteristics that may limit the uptake of these products. This is partly reflective of the fact that not all of the trading risk is captured in a single commodity price.

As the ASX futures contract is settled on the 6am price, residual risk remains in the form of exposure to the intraday prices if participants change their bids/offers or deviate from their schedule during the day. For instance, a participant might bid to withdraw more gas at the 10 am pricing schedule. If the bid is successful, the participant will face the 10am price for the incremental change in volume from the 6am schedule. As this could happen for all four intraday reschedules, the participant is no longer exposed to just the 6am price, but their individual volume weighted average price across the gas day.

Developing an exchange-traded futures contract to hedge the risk of intra-day rescheduling is likely to be administratively complex in the case of the DWGM. This is because the financial transfers are no longer dependent on movements in a single benchmark price (the 6am price), but also an individual participant’s exposure to each of the pricing intervals throughout the day. As the interval prices are generally a function of how well participants forecast their demand ahead of the gas-day, valuing this risk may be more complex for counterparties than a standard futures contract derived from a single benchmark price.

Uplift payments are another form of residual risk. Uplift payments are levied on participants to fund ancillary payments, which are required when out of merit order gas is scheduled by AEMO due to network constraints.[99] Congestion uplift, when ancillary payments are made, is levied on participants that withdraw a quantity of gas exceeding their authorised maximum interval quantity. Market participants holding authorised maximum daily quantity (AMDQ) or AMDQ credit certificates (AMDQ cc) can use this as a hedge against congestion uplift;[100] however, the benefits of an AMDQ hedge do not apply to participants not injecting gas. In other words, small users purchasing gas from the spot market without a corresponding physical position cannot hedge this risk.[101]

To summarise, a participant that has entered into an ASX futures products for the DWGM is hedged against the 6am price, but potentially still exposed to intraday prices, deviation payments/charges and uplift payments. As a result, it seems unlikely that liquid physical trading nor the development of financial risk management products can develop in Victoria with the existing design of the DWGM. While this may have been of relatively little consequence during the more stable market environment of the recent past, it will become increasingly costly in a more dynamic market.

In this context, it is clear that without significant change to the DWGM, the existing gas market arrangements in Victoria will not be able to support the outcomes envisaged by the Energy Council's Vision, nor will it be able to withstand the structural changes underway in the gas sector.

Signals and incentives for efficient investment in and use of pipeline capacity

Timely and efficient investment in infrastructure involves additions to, and expansions of, infrastructure that enable supply to meet demand while minimising the cost of excess capacity.

For efficient and timely market-led investment to occur, investors need clear signals around the need for capacity extensions and expansions (augmentations). These signals enable potential investors to make informed decisions around the size, location and timing of pipeline investment.

As outlined in the March Discussion Paper, there is currently a lack of fully effective signals to the market regarding the need for investment in new DTS pipeline capacity.[102]

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99 For instance, if the market clears at $5/GJ but AEMO has to schedule $30/GJ gas, the difference is made up for through ancillary payments to gas suppliers funded by uplift payments from gas users.

100 For more information on AMDQ and AMDQ cc, see: AEMC 2015, *Review of the Victorian Declared Wholesale Gas Market, Draft Report*, 4 December 2015, Sydney, Section 5.2.

101 Common uplift also cannot be hedged with AMDQ, while the extent of surprise uplift depends on participants' ability to forecast accurately and not change their forecasts during the gas day.

102 AEMC 2016, *Review of the Victorian Declared Wholesale Gas Market, Discussion Paper*, 3 March 2016, Sydney.

While the market carriage model is generally considered to promote both the efficient use of the DTS (that is, through the operation of the DWGM) and circumvent the need for any pipeline capacity market, it may not promote efficient and timely investment. Some market-led investment has occurred for capacity to move gas out of the DTS but investments to relieve constraints within the system are unlikely to be market-led since expected benefits attributable to such investments are unlikely to outweigh the costs to individual market participants. Specifically, market participants cannot obtain firm access rights for the transportation of gas and therefore have little incentive to underwrite investments in the pipeline system.

In the absence of market-led investment, most capacity expansions in the DTS have been progressed through the five yearly regulatory process. However, with an anticipated need to expand the network going forward to accommodate gas flowing north out of the DTS, it is therefore questionable whether it is appropriate for the risks associated with over-investment to be borne by Victorian consumers.

More generally, the issues associated with market carriage become more pronounced as capacity constraints emerge. For example, as capacity constraints emerge on a market carriage pipeline system, any inefficiencies associated with untimely regulatory-driven investment may worsen.

4.3.3 A Southern Hub for gas trading

To achieve the Energy Council's Vision and promote the NGO, the Commission recommends transitioning the existing DWGM and market carriage arrangements in Victoria to a new Southern hub gas trading model. This model will put in place the attributes required to support the development of well-functioning, workably competitive markets. These are:

- Demand and supply conditions reflected in a clear reference price.
- Allocation of firm capacity rights to signal the need for and underpin investment in pipeline infrastructure.
- Readily available market information.
- Price and volume risks can be managed and are appropriately allocated.
- Minimised barriers to entry.
- Minimised transaction costs.

When in place, these characteristics form a strong foundation for facilitated gas markets and transportation arrangements in eastern and southern Australia to promote the NGO and achieve the Energy Council's Vision.

Having considered five different reform packages for the future development of the Victorian gas market,[103] and having considered the large number of submissions received over the course of this review, the Commission recommends further developing the current DWGM market design as follows:

- To provide additional trading options for market participants, transition the DWGM, where trading and balancing occurs on a mandatory, operator led-basis, to a new model where trading would occur on a voluntary, continuous basis but underpinned by a mandatory residual balancing mechanism. A key feature would be the introduction of a trading exchange similar to that in operation at Wallumbilla, providing a low cost, anonymous and transparent way for participants to trade. While this would alter the means of exchange – the financial transactions between buyers and sellers – it would not necessitate changes to the way in which gas physically flows across the system.

  By pooling liquidity, the Southern Hub trading model will support emergence of a meaningful reference price reflective of underlying supply and demand conditions. As participants become confident in the trading of physical gas, financial risk management products will emerge to hedge physical positions.

  The emergence of such products will make it more attractive for participants to reference a hub price in bilateral contracts (as the price risk can be effectively hedged), making contracting easier and less costly as the time spent negotiating price formulation and escalation mechanisms is reduced.

  In addition, the introduction of an exchange similar to that in place at Wallumbilla will support implementation of common gas day start times, back-end systems, registration, prudentials, settlement and training, where possible. This should lower transaction costs and complexity for traders operating across multiple markets, encouraging greater participation in the east coast market.

- To support this new form of trading, replace the market carriage model and associated limited pipeline transportation rights to a system of entry and exit rights for capacity allocation. This would allow network users to book firm transportation capacity rights independently at each entry and exit point to the DTS.

  The entry-exit model would retain the general benefit of a virtual hub by pooling liquidity, while also introducing a mechanism which allows market participants to signal the need for investment in the DTS. This will support the delivery of infrastructure which is efficiently sized, in the right location and on time.

  In addition, the entry-exit system will allow market participants to book firm transportation capacity rights independently at each entry and exit point to the DTS. Capacity will be allocated on a non-discriminatory basis and participants

103 AEMC 2015, *Review of the Victorian Declared Wholesale Gas Market, Discussion Paper*, 10 September 2015, Sydney

will have the flexibility to book capacity over the long and short term, that is: over the longer term for gas they are guaranteed to flow; and on a short-term basis for additional peak flows in gas.

Secondary capacity trading will be supported and encouraged, and mechanisms which ensure the release of capacity in the short term will be included. A short-term use-it-or-lose-it (UIOLI) mechanism, similar to that being recommended on pipelines outside of Victoria, would allow for booked but unused capacity to be freed up at short notice.

Recommendation 3: *The Southern Hub to be transitioned from the existing DWGM design to continuous exchange-based trading, supported by a system of firm capacity rights.*

The Southern hub trading model would, over time, put in place the preconditions necessary to enable a liquid wholesale gas market to develop in Victoria, fundamentally improving the outcomes of the Victorian gas market. It would provide participants with greater flexibility when buying and selling gas and consumers with greater transparency around the demand and supply conditions underlying the gas price. It would also introduce a mechanism which allows the market to signal the need for investment in the DTS. This will support the delivery of infrastructure which is efficiently sized, in the right location and on time.

These outcomes are consistent with the direction that gas market development should take in order to meet the Energy Council's Vision. Further, through increasing the efficiency of the price setting mechanism in the Victorian gas market, facilitating greater access to risk management tools and improving investment signals, transaction costs should be minimised and reflected in end prices to consumers.

Importantly, the Southern Hub trading model would not undermine elements of the Victorian market that have been beneficial, both in terms of stimulating a competitive retail gas market and safeguarding the security of gas supply for Victorian customers, as to do so would not allow for the Commission's reform package to meet the NGO.

4.3.4 Work plan to progress the Southern Hub design

On the 13 May 2016, the Victorian Government provided its response to the AEMC's Draft Report for its Review of the Victorian DWGM.[104]

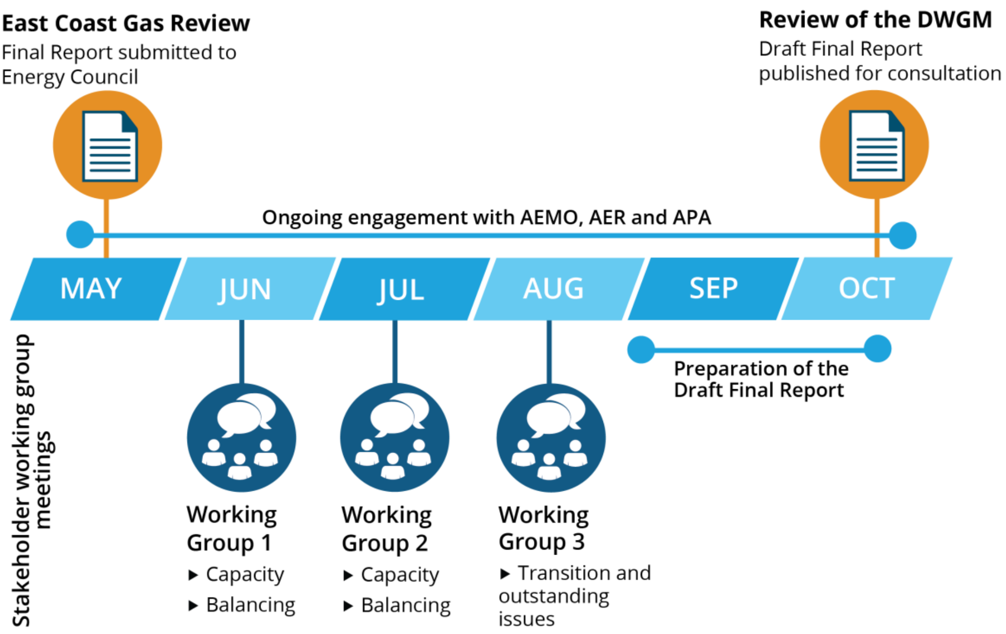
The Victorian Government notes that the AEMC's draft recommendations on developing a new Southern hub have the potential to drive benefits including the establishment of a wholesale gas reference price that would facilitate competition and provide the tools needed by Victorian retailers and wholesale customers to manage risk exposure to gas prices in an export linked market.

However, the Victorian Government has requested that a number of additional matters be considered and further analysis undertaken so that it is in a position to better assess the recommendations. The Victorian Government has also asked the AEMC to outline its plans to resolve a number of design issues and other matters related to information requirements, transitional arrangements for existing market participants and technical and system requirements.

Recognising that this work will require additional consultation with stakeholders, including with AEMO on continuing to maintain security of supply for Victorian businesses and households, the Victorian Government has granted the AEMC an extension to publish a Draft Final Report for consultation by 14 October 2016.

In order to engage with industry, AEMO and the AER on the detailed market design of the Southern Hub, the Commission has put together the work plan in Figure 4.1

Figure 4.1 Work plan to progress the Southern hub



The Commission envisages an intensive period of working with AEMO and market participants on three facets of the market design: capacity allocation, balancing and transitional arrangements. At this stage, the AEMC expects to hold three industry working groups in addition to bilateral discussions with participants and regular meetings with AEMO, the AER and APA Group. Advisory Group meetings would also continue to be organised during this period.[105]

While the Commission will be facilitating the consultation process, information and analysis from AEMO and industry participants will play a critical role in shaping the Commission's views. A high level of collaboration in the process to finalise the Southern Hub design will provide the best chance of developing a market that meets the needs of existing and new entrant gas market participants.

104 The Victorian Government's response to the AEMC's Draft Report for the Review of the Victorian DWGM is available on the AEMC website.

105 For more information on the Advisory Group, including member organisations, see Appendix C.

Once the Final Report for the Review of the Victorian DWGM is submitted to the COAG Energy Council, the Southern Hub work program will transfer to the GRG who will then be responsible for further detailed development and implementation of the AEMC's final recommendations.

4.4 Short Term Trading Market

The STTM hubs have largely provided an effective and competitive gas balancing service. They have also contributed to price transparency on the east coast, noting that before the STTM hubs were implemented the DWGM was the only source of wholesale gas price transparency.

These markets provide flexibility to new entrant retailers and large industrial users of gas, who can choose to purchase some or all of their gas requirements through the market instead of directly from producers or retailers. This optionality lowers barriers to entry and promotes competition, creating benefits for consumers.

A key feature of the STTM hubs that make the markets attractive for participants is the certainty of delivery provided through the balancing mechanism. This is a key point of difference with the GSH design where, if a seller of gas fails to deliver the agreed volumes, the buyer has limited options to make up the difference at short notice. In the STTM hubs, this gas is provided through Market Operator Service.

While the STTM hubs have served their purpose well to-date, the Commission notes that growth in trading activity at STTM hubs will be naturally limited due to their physical locations at the end of long transmission pipelines, which restricts the ability of participants to purchase STTM gas and ship it to other markets easily due to the cost of transport and/or the predominant flow of pipelines.

As a consequence, it is unlikely that the STTM will grow to include the level of trading activity required to develop into an efficient and credible reference price that participants can price contracts off and trade large volumes of gas around, as set out in the Energy Council's Vision.

Feedback from some stakeholders through the Commission's Stage 1 Report indicates that the level of complexity and costs of operating in the STTM may impose a disproportionate administrative burden on the market, relative to the role played by the STTM on the east coast.[106] Part of this issue stems from the fact that those participants who trade within their bilateral contracts incur a cost for participating in the market, irrespective of whether they derive any value from the arrangements.

The STTM hubs also represents an added level of complexity for entities wishing to operate across jurisdictions, as they are characterised by a different set of arrangements to the DWGM in Victoria, including gas day start times, although the roles of each market are similar.

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106 AEMC 2015, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, Stage 1 Final Report*, 23 July 2015, Sydney, p. 112.

4.4.1 Future evolution of the STTM

Under the recommended market framework, the Commission envisages most trading to occur at the Northern and Southern hubs as this will be where liquidity is high and transaction costs lowest. Improvements to the accuracy and timeliness of information provision, as well as access to pipeline capacity, will support exchange-based and bilateral trading at these locations.

Recommendation 4: *Simplification of the Short Term Trading Market (STTM) hubs to balancing mechanisms once the recommendations related to the Northern and Southern hubs, and pipeline capacity trading, have been implemented.*

Once the recommendations relating to the Northern and Southern hub and to pipeline capacity trading have been implemented, the Commission recommends the STTM hubs be simplified from their current design to purely support the trading of daily imbalances, thereby reducing transaction costs for participants. In continuing to evolve the STTM model, it will be important to preserve the key attributes supported by market participants, such as:

- transparent, market-based balancing to support a competitive retail market;
- certainty of delivery of supply; and
- provision of information to aid decision making.

AEMO's submission to the Wholesale Gas Markets Discussion Paper sets out a conceptual design of a simplified STTM that meets these requirements.[107] Under this high level design, the following changes would be made to the market:

- Replace the ex ante and ex post pricing mechanisms with a trade schedule where participants register transactions with AEMO. These could range from imbalance trades, on-the-day and day-ahead trades through to longer-term GSAs.
- Transactions would be carried out at the Northern and/or Southern Hub, with gas then transported to the demand hub, or bilaterally for delivery at the demand hub.
- A variation of Market Operator Service maintained to provide a competitive and transparent balancing mechanism at the hubs.
- Balancing costs paid for by participants that deviate from their trade schedule.
- Reporting, settlement and prudential services provided by the Market Operator.

While the ex ante and ex post pricing mechanisms would be removed, the Commission's considers it important that the balancing price for gas be published at the demand hubs on a daily basis, as this will facilitate transparency around balancing costs faced by market participants.

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107 AEMO, *Submission to Wholesale Gas Markets Discussion Paper*, p. 5.

Evolving the STTM in this way would result in participants not having to submit price quantity pairs on a daily basis to ensure their gas is scheduled by the market. Additionally, AEMO would no longer be required to maintain systems to calculate provisional, ex ante or ex post prices. The Commission considers that much of the complexity and costs associated with the market design can be removed, while maintaining the core functionality participants will require in the context of the new market framework.

Box 4.5 provides an example of how a large user could purchase gas from either the Northern or Southern hub to be consumed in Adelaide.

Box 4.5 Buying gas for consumption in Adelaide

Under the current arrangements, small volumes of gas are traded on the STTM hubs at the major demand centres across the east coast. While this provides participants with a convenient means of purchasing or selling incremental gas, it splits trading liquidity and is therefore unlikely to produce a reference price for gas that participants have confidence in and against which risk management products could be based on.

To foster a wholesale reference price for gas on the east coast, the Commission has recommended concentrating trading at a Northern and Southern Hub, supported by changes to encourage development of liquid market for pipeline capacity trading. Under these arrangements, a large user looking to utilise a trading market to purchase gas could:

- Purchase a week-ahead product on the exchange at the Southern Hub for the delivery of gas over a seven day period; on a similar anonymous electronic exchange, purchase secondary pipeline capacity on the SEA Gas Pipeline directly from a shipper selling spare capacity to transport the gas to Adelaide over the next week.

- Purchase a day-ahead product on the exchange at the Northern Hub for delivery the following gas day; on the relevant pipeline capacity exchange, participate in a daily auction of as-available capacity on the South West Queensland Pipeline (SWQP) and Moomba to Adelaide Pipeline System (MAPS) simultaneously, in order to secure capacity to ship the gas to Adelaide the following day.

After the transaction(s) is complete, the large user would notify AEMO (as the Adelaide hub operator) of any gas it was shipping to the hub and the amount of gas it expected to withdraw from the hub, the day before the gas day. If the user deviated from its schedules, balancing services would be required and the user would receive a payment if long gas or pay a charge if short gas.

Encouraging growth in liquidity and a meaningful reference price at the Northern and Southern hubs, along with reforms to pipeline access and information provision, will provide participants with greater flexibility for buying and selling gas than currently exists. Because of this, there will not be a strong requirement to trade at the demand centres and the benefits of retaining the STTM hubs as independent pricing points is likely to outweigh the costs.

The Commission recognises some gas users have come to rely on the STTM hubs in recent times as a source of competitive gas supply that is critical to the ongoing operation of their businesses.[108]

Before recommending that the transition of one or more of the STTM hubs commences, the Commission will need to be satisfied that the recommendations related to the Northern and Southern hub, and to pipeline capacity trading, have been implemented. The Commission envisages that it would make this recommendation as part of its biennial review of trading liquidity in the wholesale gas and pipeline capacity trading markets, as discussed above and in further detail in Appendix F.

Most submissions to the Stage 2 Draft Report support simplifying and reducing the costs associated with the STTMs. Stanwell and QGC put forward the option of transitioning the STTM to balancing markets earlier than planned or, at a minimum, converting the Brisbane STTM to balancing, which would shift wholesale trading to Northern Hub.[109] In contrast, ERM Power considers the removal of the STTM will create barriers to entry, but accept the AEMC's proposal to only proceed with changes if other reforms have led to sufficient trading liquidity.[110]

108 Wholesale Gas Markets Discussion Paper Submissions: Visy, pp. 4-5; and Qenos, pp. 2-4. Stage 1 Draft Report Submissions: Australian Paper, pp. 2-3; and CQ Partners, pp. 1-3.

109 Stage 2 Draft Report Submissions: AER, AGL, Stanwell, QGC, RWE Trading, Santos, EUAA, AEMO, APPEA, APA Group, Jemena, Esso, PIAC.

110 Submission to the Stage 2 Draft Report, ERM Power.

5 Transportation capacity markets

Box 5.1 Recommendations and summary of chapter

To improve the efficiency with which transportation capacity (pipeline and hub services) is allocated and utilised in the east coast, the Commission recommends four secondary capacity trading related initiatives.

Recommendation 5: *Development and introduction of a daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services which happens shortly after nomination cut-off time. This auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in-kind, offer at least all contracted but un-nominated capacity, and accommodate nominations or renominations by incumbent shippers after the auction is conducted.*

Recommendation 6: *Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services, which where possible and appropriate apply across the eastern Australian gas market. Standards to be developed are for key operational, prudential and other contractual provisions in GTAs, CTAs and Operational GTAs, and provisions in contracts used for exchange based trading on the capacity trading platform. Counterparties to existing contracts should not be materially disadvantaged through the standardisation process.*

Recommendation 7: *Creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms. Trades carried out through the capacity trading platform to be given effect through an operational transfer. For other secondary capacity trades, bare transfers will be allowed but the seller will be required to offer the buyer the option to use an operational transfer.*

Recommendation 8: *Publication of information on all secondary trades of pipeline capacity and hub services. The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties, and should occur at or shortly after the time the transaction is entered into.*

The Commission has also highlighted **preferred** outcomes which the GRG should pursue unless it is clear that there are greater benefits in alternative approaches and **suggested** outcomes given the in-principle benefits that may arise from their implementation. These are detailed in Table 5.1.

Together the Commission expects these initiatives to facilitate more secondary capacity trading and support the development of a liquid wholesale gas market by:

- using market based processes to allocate capacity on a non-discriminatory basis to those that value it most highly;
- reducing the search and transaction costs associated with secondary trades;
- reducing information asymmetries, which will aid the price discovery process; and
- improving the incentive shippers have to trade capacity.

5.1 Introduction and context

The achievement of the NGO and the Energy Council's Vision of a liquid wholesale gas market depends critically upon the efficiency with which the capacity of pipelines and the compressors used in the provision of hub services (collectively 'transportation capacity' or 'capacity') is allocated.

Until recently, market fundamentals were more predictable and long-term contracts were relatively effective in allocating gas and transportation capacity. However, with the changes currently underway in the east coast gas market, allocating gas to those that value it most is becoming more challenging and increasingly linked to the efficiency with which transportation capacity is allocated between shippers and used, particularly on contractually congested assets.[111] The ability to trade transportation capacity between shippers is therefore becoming increasingly important in the east coast market and will be critical to the success of the development of a liquid wholesale gas market and efficient reference price in the east coast.

Although some steps have been taken over the last two years to better facilitate capacity trading between shippers, there are, as stakeholders have pointed out in both stages of this review, a number of factors that are limiting the ability of prospective shippers to access competitively priced secondary[112] transportation capacity. These limitations include:

- high search and transaction costs, particularly for shorter term capacity trades;
- the bespoke nature of transportation agreements, which can impede the development of fungible capacity products and limit the pool of potential buyers and sellers; and
- the lack of public information on the prices paid for transportation capacity, which means shippers are unable to readily assess the market value of capacity.

These observations are broadly consistent with the finding from the ACCC's Inquiry that while there is evidence of capacity being bought and sold (predominantly under longer term contracts), the factors outlined above are acting as barriers to trade and limiting capacity utilisation and gas flows:

> "Capacity, including secondary capacity/services, is being bought and sold. However, information transparency, search and transaction costs, and also the pricing of transportation are barriers to further capacity utilisation and gas flows.[113]"

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111 Contractual congestion occurs when a shipper is unable to gain access to an asset, despite it having physical capacity, because another shipper owns the rights to that capacity and is unable or unwilling to sell that capacity.

112 'Secondary' refers to capacity traded between shippers, as opposed to 'primary' capacity which is sold by a pipeline owner to a shipper.

113 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 149.

To address these issues, the Commission recommends a number of initiatives which collectively it expects will foster the development of a more liquid market for secondary capacity by:

- enabling capacity to be allocated on a non-discriminatory basis to those that value it most highly through market based processes and, in so doing, improve the efficiency with which capacity is used on pipelines;
- reducing search and transaction costs;
- aiding the price discovery process by reducing informational asymmetries and, in so doing further reduce search and transaction costs, enable more informed decisions to be made, and provide shippers with the confidence that access to capacity is being provided on a non-discriminatory basis; and
- providing capacity holders with a greater incentive to trade capacity.

The recommended initiatives are summarised in Table 5.1, which also outlines the Commission's preferred and suggested outcomes which the GRG should consider when developing the reforms.

Table 5.1 Required, preferred and suggested transportation capacity market outcomes

Recommendation	Required outcomes (included in recommendation)	Preferred outcomes	Suggested outcomes
Auction for contracted but un-nominated capacity	• A daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services. • Auction happens shortly after nomination cut-off time. • Reserve price of zero dollars, with compressor fuel provided by shippers in-kind. • At least all contracted but un-nominated capacity placed for sale through auction. • Accommodate nominations or renominations by incumbent shippers after the auction is conducted.	• Combinatorial auction where multiple buyers and sellers can simultaneously coordinate trades, managing the complementarities between different pipeline segments. • Single round auction to reduce complexity and opportunities for anti-competitive behaviour including collusion between participants. • Bidders pay the value of their winning bids ("first-price" rule) to reduce complexity. • Algorithm determines the winning combination of bids by maximising profit (constrained by requirement that at least all contracted but un-nominated capacity is put on sale in the auction). • Capacity purchased in the auction curtailed before (ie, earlier than) firm capacity. • Single auction across the east coast market, in order to optimise allocation across as many products as possible. • Exemption from the auction for pipelines serving a single user.	• As available rights in current GTAs to be phased out to avoid them competing with rights allocated in the auction. • Exempting on a case-by-case basis pipelines that are not fully contracted from needing to conduct the auction. • The auction to be run by the same instruction(s) which run the capacity trading platform.

Recommendation	Required outcomes (included in recommendation)	Preferred outcomes	Suggested outcomes
Standardisation of key primary and secondary capacity contractual terms	• Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services. • Where possible and appropriate apply across the eastern Australian gas market. • Standards to be developed are for key operational, prudential and other contractual provisions in GTAs, CTAs and Operational GTAs, and provisions in contracts used for exchange based trading on the capacity trading platform. • Counterparties to existing contracts should not be materially disadvantaged through the standardisation process	• Shippers provided greater flexibility to change their receipt and delivery points.	
Capacity trading platform(s)	• Creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms. • Trades carried out through the capacity trading platform to be given effect through an operational transfer. • Bare transfers will be allowed but the seller will be required to offer the buyer the option to use an operational transfer.	• Single capacity trading platform operating across the east coast. • As many services as possible capable of being traded on the platform (eg, transportation services, hub services and pipeline storage services), recognising the need to avoid unnecessary complexities. • Trades conducted outside the capacity trading platform to be advertised ahead of time on the capacity trading platform listing service.	
Publication of information on secondary capacity trades	• Publication of information on all secondary trades of pipeline capacity and hub services. • The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties. • Publication should occur at or shortly after the time the transaction is entered into		

5.2 Auction for contracted but un-nominated capacity

In the Stage 2 Draft Report, the Commission recommended that an auction for contracted but un-nominated capacity with a regulated reserve price be introduced. In the subsequent Discussion Paper, the Commission further elaborated on the rationale for this auction, discussed key outcomes for the auction design, and laid out preliminary preferences for outcomes.[114] Stakeholders were invited to comment on these matters through submissions.

5.2.1 Current issues in the market which the auction will address

Currently, a shipper that has contracted capacity on a pipeline is typically required to nominate their usage for any given day by a defined time on the day before. Typically, after a pre-determined nomination cut-off time, any capacity that the shipper has contracted but not nominated to use is "lost" to the shipper, and the pipeline owner is able to re-sell this capacity to another shipper who might value it.

A shipper with contracted capacity currently has an incentive to sell unwanted capacity prior to the nomination cut-off time, in order to recoup some revenue that would otherwise be lost to that shipper. This might occur immediately before the nomination cut-off time, or at any time before, depending on the value it placed on holding on to the capacity in case it is required.

However, some shippers may have a countervailing incentive not to sell capacity. Determining the likely future value of capacity and making a judgement whether to sell it is not a core business function for many shippers. The cost and effort of doing so, and the risk of being short of capacity if the sale occurs a long time before the nomination cut-off time, may exceed the revenue generated. While this may be rationale behaviour on the part of the incumbent shippers, it may be resulting in contractual congestion, whereby a pipeline has physical capacity but a shipper which would wish to use that capacity is unable to do so due to it being contractually held by another party.

The Commission recognises these issues, and is recommending a suite of measures to help reduce transaction costs and inform shipper decision making, as described throughout the rest of this chapter.

Furthermore, the ACCC has identified evidence in the case of some regional pipelines that shippers are deliberately withholding capacity in order to improve their competitive position in up- or downstream markets, although this behaviour is not widespread and has not been observed on major pipelines.[115] The ACCC has tasked itself to consider whether the availability or pricing of capacity on regional pipelines

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114 Australian Energy Market Commission, *East Coast Wholesale Gas Market and Pipelines Frameworks Review*, March 2016.

115 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 19.

raises any concerns as a breach of the misuse of market power provisions or the exclusive dealings provisions of the Competition and Consumer Act (2010).[116]

As the only seller of capacity beyond the nomination cut-off time, the pipeline owner has the ability and incentive to price contracted but un-nominated capacity above levels expected in a workably competitive market. The ACCC has found evidence to suggest that the pricing of as available and interruptible services of some pipelines may affect the efficient utilisation of capacity.[117] The Commission is concerned that high prices for such capacity, *in combination with the shippers' limited incentives to trade*, may be resulting in inefficient outcomes that the recommended auction might address.

There may also be a co-ordination failure which arises when allocating capacity through the market. The market for contracted but un-nominated capacity is complex and involves multiple agents. Multiple buyers need to transact with multiple sellers, preferably simultaneously, in order to reach the welfare-maximising allocation of capacity. Currently, they have no means of doing so apart from bilateral negotiations between participants which may be lengthy, complex and expensive, or infeasible, particularly for short term trades (see example in Box 1.5). The ACCC notes that evidence presented to them through its inquiry highlights the difficulties in achieving short term deals to coordinate delivery of gas over multiple legs.[118]

5.2.2 How the auction will address these issues

The day-ahead auction for contracted but un-nominated capacity will address these issues, in combination with the other recommended improvements to the secondary capacity market.

Firstly, in instances where shippers simply forego the opportunity to sell capacity because it is not core-business, a prospective shipper's alternative is to purchase contracted but un-nominated capacity from the pipeline owner. However, high prices for this capacity may be pricing prospective shippers out of the market. The auction would provide prospective shippers the opportunity to purchase competitively priced capacity. In the limited cases identified by the ACCC where an incumbent shipper is deliberately withholding capacity, the auction would also improve the shipper's incentive to sell the capacity prior to the nomination cut off, given that the auction will limit the incumbent shippers' ability to block access to a competitor.

The auction provides a pricing and allocation mechanism that is less costly for participants, and, depending on its design, the auction may provide a platform to simultaneously coordinate trades - allocating capacity in an efficient manner to the combination of shippers that value it highest as indicated through their bids.

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116 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 21.

117 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 151.

118 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 151.

5.2.3 Final recommendation

In their submissions to the Discussion Paper, stakeholders including AEMO and shippers expressed strong in-principle support for the auction.[119] No stakeholders expressed opposition to the day-ahead auction concept.

Given the likely benefits of the auction, supported by stakeholder submissions, the Commission recommends the COAG Energy Council agrees to the development and introduction of a daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services which happens shortly after nomination cut-off time. This auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in-kind, place for sale at least all contracted but un-nominated capacity, and accommodate nominations or renominations by incumbent shippers after the auction is conducted.

Recommendation 5: *Development and introduction of a daily, day-ahead capacity auction for contracted but un-nominated pipeline capacity and hub services which happens shortly after nomination cut-off time. This auction is to have a reserve price of zero dollars, with compressor fuel provided by shippers in-kind, offer at least all contracted but un-nominated capacity, and accommodate nominations or renominations by incumbent shippers after the auction is conducted.*

The COAG Energy Council should agree to the development of required changes to the NGL and NGR and any other relevant instruments that are necessary to support the implementation of this auction, with the detailed design work being progressed by the GRG.

In making this recommendation the Commission has included a number of required outcomes which must be progressed in order for the package of reforms to be achieved. Other outcomes that must also be considered by the GRG have also been progressed by the Commission. These measures would benefit from further consideration and have been categorised as 'preferred' or 'suggested' in this chapter, depending on the relationship of each outcome to the auction rationale, and whether or not the issue has been contentious among stakeholders.

The Commission does not recommend the immediate introduction of a long term use-it-or-lose-it (UIOLI) mechanism. However, should the recommended auction for contracted but un-nominated capacity combined with improvements to facilitate secondary capacity trading (described in this chapter) result in insufficient levels of trade, then the Commission recommends that the introduction of a long term UIOLI mechanism should be re-considered. Long term UIOLI mechanisms are described in Box 5.2.

119 See for example submissions on the Discussion Paper: ERM, p. 4; QGC, p. 5; AEMO, p. 2, AGL, p. 2; ENGIE, p. 4; APA, p. 12; EnergyAustralia, p. 1; Central Petroleum Limited, p. 2.

Box 5.2 Long term use-it-or-lose-it mechanisms

Under a long term UIOLI mechanism, shippers who systematically underutilise their contracted capacity would be required to surrender a defined proportion of this capacity back to the pipeline owner for resale to another shipper. The capacity product released would be medium or long term (perhaps a month, season, or year). The underutilised capacity would generally be determined through a retrospective review of flow and usage patterns.

The recommended auction for contracted but un-nominated is in effect a day-ahead UIOLI mechanism. While a longer-term UIOLI mechanism might result in more (and more valuable) capacity being released to other shippers, it has two clear drawbacks compared to the recommended day-ahead UIOLI mechanism. The long term mechanism:

- would impinge on the existing property rights of shippers (whereas the day-ahead mechanism recommended would improve the process by which capacity that has typically already been lost to a shipper is re-allocated to other shippers); and
- may have a more material impact on investment signals. Prospective shippers may be better able to meet long term capacity requirements by purchasing capacity released through the longer-term UIOLI mechanism, with the potential for free-rider effects.

For these reasons, the Commission is not recommending the introduction of a long term UIOLI mechanism at this stage.

5.2.4 Auction design - required outcomes

Reserve price

The appropriate reserve price for the auction is zero, with compressor fuel to transport gas along capacity purchased provided by shippers in-kind. This will support the rationale for the day-ahead auction of providing access to capacity at a price consistent with that in a competitive market by addressing monopoly pricing behaviour on the part of pipeline owners for as-available capacity. It will allow the shippers that value the capacity most highly access to that capacity providing they are willing to pay at least the cost of its provision.

In the Stage 2 Draft Report, the Commission suggested that setting the reserve price at short run marginal cost (SRMC) may be appropriate. SRMC describes the incremental cost incurred by pipeline operators to supply additional pipeline capacity without incurring any additional infrastructure investment costs. The Commission engaged NERA Economic Consulting (NERA) to consider the methodology for setting the reserve price at SRMC, whether the SRMC is an appropriate reserve price for the auction, and alternatives to SRMC.[120]

In keeping with the Commission's findings in the Stage 2 Draft Report, NERA considered that setting the reserve price at SRMC is appropriate as raising the auction reserve price above SRMC would affect allocative efficiency. It would mean that a potential shipper willing to pay more than SRMC but less than the alternative auction reserve price would be priced out of the pipeline. In other words a potential shipper that would be willing to pay more than society's incremental costs for providing the service would not get it - an economically inefficient result.

NERA noted that when un-nominated capacity is available for sale on the Commission's proposed auction, the SRMC of gas transmission closely approximates the cost of incremental gas used to run compressors. That is, no other components materially contribute to the SRMC.

There is a clear advantage of expressing the SRMC as a percentage of total gas throughput, as the price of gas is not required to determine the SRMC, and might otherwise be difficult to calculate (indeed, the opaque nature of gas prices on any given day on in the east coast of Australia is one of the wider prompts of reform). Furthermore, we understand it common practice for shippers to cover the cost of compressor fuel by providing it in-kind in existing long-term GTAs.

Given that compressor fuel usage as a percentage of gas transported does not vary on a particular pipeline route over time, shippers would have knowledge of the amount of gas in-kind that they would be required to provide were they to buy capacity in the auction prior to the auction taking place. They can therefore factor this into their bids.

In submissions on the Discussion Paper, multiple stakeholders expressed support for a reserve price of zero with fuel in kind.[121] No stakeholders opposed this methodology for determining the reserve price.

Quantity of capacity to be auctioned

All contracted but un-nominated capacity should be auctioned, within technical constraints. Pipeline owners should not be permitted to withhold capacity. This will support the rationale for the day-ahead auction of increasing market liquidity by providing access to all available capacity and preventing pipeline owners from restricting supply and hence increasing the price outcomes of the auction.

As noted in the Stage 2 Draft Report, were the pipeline owner able to determine the amount of un-nominated capacity to be auctioned, it may have an incentive to withhold some capacity in order that the auction clearing price is increased (with the overall effect of higher profits).

120 See NERA Economic Consulting, *Determining a reserve price for a short term gas transmission auction*, February 2016.

121 See submissions on the Discussion Paper: APGA, p. 21; Stanwell, p. 9; Epic, p. 6; ERM, p. 6; APLNG, p. 5; APA, p. 16; QGC, p. 9 and AGL, p. 3.

The Commission therefore suggested that it may be appropriate for the quantity of capacity to be auctioned to be set through a regulated process. The Commission understands that determining the quantity of technically feasible contracted but un-nominated capacity is a relatively trivial calculation, such that it could be directly set out in the NGR, or determined by the pipeline owners through a process approved by the AER.

In submissions to the Discussion Paper, AEMO and APLNG supported the concept of an AER approved methodology, with AEMO stating that the process of determining the appropriate quantity is similar to the task that pipeline operators currently perform when determining the STTM pipeline hub capacity.[122] Other stakeholders argued that the process is more complex, and cannot be codified into a simple formula.[123]

The GRG should consider the appropriate mechanism by which pipeline owners are required to release all technically feasible contracted but un-nominated capacity through the auction.

Nominations by incumbent shippers

Nominations and renominations by incumbent shippers after the auction is conducted should be accommodated.

The Stage 2 Draft Report noted that under typical GTAs, shippers lose their firm capacity rights at the nomination cut-off time. This nomination cut-off time typically occurs in the afternoon of the day before the day the gas is to be shipped, after which the shipper's un-nominated capacity can be sold in the auction.

However, in some cases there are explicit or implicit rights for incumbent shippers that continue to exist after this point. Firstly, some GTAs have a nomination cut-off which is later than the typical time. Shippers under these arrangements may retain an explicit, contractually firm right to nominate after the time of the day-ahead auction, which may lead to conflict if both services cannot be accommodated simultaneously.

In addition, some shippers have historically retained the ability to nominate after the cut-off. These shippers value the ability to nominate because their actual gas transportation requirements vary compared to their forecast requirements made at the nomination cut-off time. This is not a contractually firm right, and would not be accommodated if the pipeline owner were to subsequently sell the capacity on a firm basis to another shipper such that the capacity of the pipeline was unable to accommodate the (re)nomination. Nonetheless, the Commission understands that shippers' (re)nominations have nearly always been accommodated in practice in these circumstances.

There are different ways of accommodating such (re)nominations. One option is for some or all capacity to be sold as 'interruptible' in the auction. For those shippers which have contractual firm rights to nominate capacity after the auction, this would

122 See submissions on the Discussion Paper: AEMO, p. 10; APLNG, p. 5.

123 See APA submission on the Discussion Paper, p. 14.

leave their rights unaffected. For those shippers that do not have contractual firm rights but have an implicit ability to nominate, this ability would be formalised and therefore strengthened.

The advantage of auctioning interruptible capacity is that it does not negatively impact the contractual or implicit ability of incumbent shippers to nominate their capacity close to the time the capacity is required. The disadvantage is that the quality of the product sold in the auction is reduced, which may impact trading liquidity - a key auction rationale.

Another option to accommodate nominations would be to run the auction more frequently than on a daily basis. Changes in the level of capacity available due to nominations could then be taken into account in each successive iteration. However, given the cost (including time) of running the auction multiple times, this is unlikely to be a feasible approach.

In submissions on the Discussion Paper, most stakeholders were in favour of capacity in the day-ahead auction being offered on an interruptible basis.[124]Others argued for firmer rights to be sold at the auction, or for a combination of firm and interruptible capacity, or for some capacity to be withheld to accommodate renominations.[125]

If the GRG agrees that some or all capacity should be sold through the auction on an interruptible basis, it should undertake further work to determine the ratio of firm to interruptible capacity which should be sold. The GRG should otherwise determine an alternative solution to ensure nominations and renominations after the auction are accommodated.

5.2.5 Auction design - preferred outcomes

The following outcomes are classified as 'preferred', which the Commission recommends the GRG should pursue unless it is clear that there are greater benefits in alternative approaches.

Individual or combinatorial allocation

The preferred outcome is a combinatorial auction. This will provide a platform where multiple buyers and multiple sellers can simultaneously coordinate trades, managing the complementarities between different pipeline segments. However, the additional cost due to the greater complexity of a combinatorial mechanism has not been estimated, and may be material. Further work by the GRG is needed to obtain an estimate of the relative magnitude of these costs and benefits.

124 See submissions on the Discussion Paper: Stanwell, p. 11; Santos, p. 4; Epic, p. 7; APA, p. 17; Australian Energy Council, p. 17.

125 See submissions on the Discussion Paper: ERM, p. 5; QGC, p. 1, APLNG, p. 5.

In submissions on the Discussion Paper, shippers largely supported the combinatorial format.[126] AGL expressed a preference for the allocation of rights for the full length of each pipeline, but stated that if multiple segments are allocated, this should be done combinatorially.[127] Two pipeline owners, APGA and APA, described a preferred process for the auction (bids specifying price, receipt and delivery points and volume) which was effectively combinatorial.[128]

Further detail on combinatorial auctions is provided in Appendix G.

Number of rounds in the auction

The preferred option for this design outcome is a single round auction. A multi-round auction may be extremely difficult to implement in an already complex setting with multiple buyers placing bids for multiple items in various quantities, all having to be done quickly. A single round auction also minimises opportunities for anti-competitive behaviour including collusion between participants.

However, if a feasible means of incorporating multiple rounds within the timeframe of the auction were to be found, this might have benefits in terms of price discovery without undermining the core aims of improving market liquidity and allocative efficiency.

In submissions on the Discussion Paper, all of the stakeholders who commented on the issue supported a single round for the auction.[129]

Prices paid by winning bidders

The preferred option for this design outcome is a first price rule, under which bidders pay the value of their winning bid. Although this has the advantage of simplicity, bidders may be concerned about paying more than they need to. This may lead them to submit bids which are lower than their willingness to pay, leading to inefficiencies. Under a second price rule, the bidder would pay the minimum amount they would have needed to bid in order to win the auction, creating an incentive to bid their true values.

However, determining the 'second price' may be unfeasible or mathematically complicated in a combinatorial auction. Under such an approach, there is no obvious way of ranking bids for different 'packages' of items since they are not directly comparable, as different shippers will bid for different 'packages' of pipeline products.

For example, if there is a bid for capacity from A to B **and** B to C, it is not obvious how to compare this to a bid for A to B **and** B to E, or to a bid for A to B **only.**

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126 See submissions on the Discussion Paper: ENGIE, p. 4; ERM, p. 6; APLNG, p. 4.

127 See AGL submission on the Discussion Paper, p. 2.

128 See submissions on the Discussion Paper: APA, p. 12; APGA, pp. 16-17.

129 See submissions on the Discussion Paper: APGA, p. 18; Stanwell, p. 8; APLNG, p. 4, APA, p. 13, AEMO, p. 9; AGL, p. 2.

The choice of an appropriate pricing rule for the auction is therefore a trade-off between simplicity and potential benefits from encouraging 'honest' bidding. In submissions on the Discussion Paper, all of the stakeholders who commented on the issue supported a first price rule for the auction.[130]

Determining the winning combination of bidders

The preferred method of determining the winning combination of bids is to maximise profit. For efficiency purposes, the optimal allocation should maximise economic surplus. This is equivalent to profit, assuming that bids are a real reflection of bidders' values.

It should be noted that the allocations reached through profit maximisation under the combinatorial auction would be different from those reached through the pipeline owners' existing incentive to maximise profit. This is because the auction would make it compulsory to offer contracted but un-nominated capacity to the market, at or above the regulated reserve price. That is, profit would be maximised under the condition that capacity cannot be deliberately held back from the market above the cost of providing that capacity.

In submissions on the Discussion Paper, Stanwell and APLNG supported using profit maximisation to determine the winning bids.[131] PIAC suggested capacity maximisation as the appropriate criterion.[132] The Commission considers such an approach is unlikely to maximise economic efficiency because it does not take into account the value placed on capacity by shippers.

Allocation of auction revenue

The preferred method of allocating auction revenue is to give it to pipeline owners, after the costs of running the auction have been recovered. This is consistent with the status quo, as pipeline owners currently have the ability to sell as-available capacity. The Commission considers that revenue should not be allocated to the specific incumbent shipper who, in the absence of the auction, would have retained rights over the capacity. This is in order to maintain the incentive for shippers to sell capacity prior to the auction in order to recoup some revenue.

However, so long as the residue is not allocated to incumbent shippers, it is conceivable that it could be allocated to another party without damaging the incentive to trade capacity before the auction. For example, the residue might be allocated to the market operator (if this is not the pipeline owner), or to all shippers on a pipeline (which would include the incumbent shipper, but also other shippers, meaning that the incumbent shipper would only partially recoup revenue).

130 See submissions on the Discussion Paper: APGA, p. 17; Stanwell, p. 8; APLNG, p. 4.

131 See submissions on the Discussion Paper: Stanwell, p. 8; APLNG, p. 4.

132 See PIAC submission on the Discussion Paper, pp. 5-6.

In submissions on the Discussion Paper, pipeline owners agreed that they should be allocated the residue, while shippers considered it should be allocated to them.[133] AEMO agreed with the Commission that allocating residue to pipeline owners is likely to encourage contract-holding shippers to participate in the secondary trading market, ahead of the auction.[134]

Curtailment order

The preferred outcome is for capacity purchased in the auction to be curtailed before firm capacity. Curtailment arises due to physical congestion – more capacity has been scheduled than can be physically shipped by the pipeline system (for example due to an asset failure). It therefore does not directly relate to the auction rationale.

The key trade-off in determining the curtailment order is that placing the capacity released through the auction high in the curtailment order (ie, late to be curtailed) increases the value of that product, but implicitly reduces the value of all products at or above it in the curtailment order.

In submissions on the Discussion Paper, there was general support for capacity bought in the auction being curtailed before firm capacity.[135]

Geographic scope of the auction

The preferred outcome for the auction's geographic scope is a single auction across the east coast market. From an efficiency perspective, a whole-network auction would optimise allocation across as many products as possible, given complementarities between different lengths of pipeline capacity.

However, the benefits of conducting a single auction across the network in terms of greater integration need to be balanced against the costs of additional complexity. This includes accommodating the different physical nature and technical capacities of different pipelines, and developing a communications system or interface between different pipeline owners and a central platform.

In submissions on the Discussion Paper, some stakeholders considered that the complementarities between pipelines are likely to become stronger over time, and therefore supported a whole-network auction.[136] Others raised the possibility of initially conducting an auction on a per-pipeline basis, but transitioning to a broader

133 See submissions on the Discussion Paper: APGA, p. 19; Santos, p. 4; APLNG, p. 4; Australian Energy Council, p. 2; ENGIE, p. 6; AGL, pp. 2 -3.

134 See AEMO submission on the Discussion Paper, p. 9.

135 See submissions on the Discussion Paper: Jemena, p. 3; APGA, p. 22; Stanwell, p. 11; Santos, p. 4; Epic, p. 7.

136 See submissions on the Discussion Paper: AEMO, p. 9; QGC, p. 7.

scope in future.[137] Pipeline owners tended to support the auction being conducted on a per-pipeline basis.[138]

Exemption for pipelines that serve a single user

In the Stage 2 report, the Commission noted that some pipelines serve only a single facility and consequently may only be used by a single user – either the facility itself, or the facility's retailer.[139]In such circumstances, an auction for un-nominated capacity may achieve little as there would be no prospect of un-nominated capacity being resold to another shipper. This view appears to be uncontroversial - there was little comment on this issue from stakeholders, apart from QGC agreeing there is limited value in applying the auction to single shipper facilities.[140]

5.2.6 Auction design - suggested outcomes

The recommendations classified as 'suggested' are those that the Commission considers have in-principle benefits, but require more detailed consideration by the GRG.

As available rights

The suggested outcome is for as available rights in current GTAs to be phased out, as they will compete with the rights allocated in the auction, which effectively releases available contracted but un-nominated capacity on a daily basis. If as available rights are given priority over the rights purchased in the auction, this could mean that capacity is not being allocated to its highest value use, as there may be an auction participant(s) who values the capacity more.

In submissions on the Discussion Paper, few stakeholders chose to comment on the proposed phasing out of as available rights. QGC agreed that these rights could be inconsistent with the auction, while Jemena argued that the two can co-exist.[141]

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137 See submissions on the Discussion Paper: APGA, p. 18; Jemena, p. 3; Stanwell, p. 7.

138 See submissions on the Discussion Paper: Jemena, p. 3; APGA, p. 16; APA, p. 14

139 Where a single shipper which is acting as a retailer owns most or all of the rights to the capacity of a particular pipeline, it may have market power over the consumers of gas on that pipeline. The situation may arise because a Gas Supply Agreement between a consumer and shipper expires before the Gas Transportation Agreement between the shipper and pipeline owner expires. In this instance, the retailer may be able to negotiate the (new) Gas Supply Agreement with the consumer at a price above that which would be expected in a workably competitive market, because no other retailer is able to access the pipeline to ship gas to the consumer. The ACCC has identified that this may be a problem on regional pipelines, and will consider further whether this behaviour breach the misuse of market power provisions or the exclusive dealing provisions of the Competition and Consumer Act (2010). See ACCC, *Inquiry into east coast gas market*, April 2016, p. 21.

140 See QGC submission on the Discussion Paper, p. 8.

141 See submissions on the Discussion Paper: Jemena, p. 3; QGC, p. 9.

To the extent that as available rights in GTAs remain (either permanently or transitionally), the GRG should consider how these should be accommodated into the auction design.

Exemption for pipelines that are not fully contracted

The suggested option is to exempt on a case-by-case basis pipelines that are not fully contracted.

A key part of the auction rationale is to address contractual congestion and to undermine the market power held by pipeline owners in the market for day-ahead capacity.

Neither of these rationales appear to apply in the case of pipelines which are less than fully contracted. Contractual congestion occurs where physical pipeline capacity is available, but cannot be utilised by shippers that value it because it is contractually held by another party. By definition, pipelines that have a low proportion of capacity contracted are not contractually congested.

Similarly, the incentive and ability to exercise market power is weaker in cases where significant pipeline capacity is not contracted.

On the other hand, there are a number of reasons to suggest that pipelines should not be exempted on the basis of how much capacity is contracted. For example, a key benefit of the auction is that it can simultaneously allocate products across the system, taking complementarities into account. Exempting some pipelines will inhibit the ability of the auction algorithm to reach the welfare-maximising allocation.

Furthermore, exempting pipelines that are not fully contracted may create an incentive to 'game' the system by deliberately remaining less than fully contracted, in order to avoid being required to participate in the auction.

In submissions on the Discussion Paper, pipeline owners and some shippers agreed with the Commission's rationale for exempting pipelines that are not fully contracted in order to protect the primary capacity market, although shippers emphasised that these exemptions should be on a case by case basis and limited in scope.[142]Other participants questioned this rationale, with AEMO suggesting that excluding some pipelines would undermine the combinatorial allocation and AGL raising concerns about pipeline owners 'gaming' the exemptions.[143]

The Commission considers that the GRG should undertake further work to determine an appropriate methodology for determining exemptions.

142 See submissions on the Discussion Paper: Jemena, p. 3; APGA, p. 20; Stanwell, p. 9; Epic, p. 4; APLNG, p. 4; APA, p. 15;

143 See submissions on the Discussion Paper: AEMO, p. 2; AGL, p. 2; QGC, p. 8.

Institutional setting of the auction

There are multiple options for the appropriate body to conduct the auction. The appropriate choice relates to other aspects of the auction design and other secondary capacity trading recommendations in this chapter, including the management of the capacity trading platform(s), and the geographical scope of the auction (single pipeline or whole network), which have yet to be determined by the GRG.

Potential institutions to run the auction include:

- AEMO;
- individual pipeline owners;
- a joint venture between pipeline owners; or
- other parties with relevant capabilities (eg the ASX).

In submissions on the Discussion Paper, most shippers as well as PIAC recommended that the auction be run by AEMO.[144] However, pipeline owners argued that they have better operational knowledge to conduct the auction.[145] AEMO suggested that either it, or a joint venture between pipeline owners, should operate the auction, and that this should be combined with operation of the capacity trading platform.[146]

The Commission suggests there may be benefits in the auction being run by the same institution(s) which run the capacity trading platform (discussed in section 5.4.3).

5.2.7 NGL and NGR changes

As discussed in section 3.1.2, it is likely that NGL and NGR changes, as well as newly created subordinate instruments, will be required to implement the auction for contracted but un-nominated capacity.

The GRG will be responsible for developing these changes and proposing them to the COAG Energy Council and the AEMC.

While the exact detail of the required changes will only be known once the GRG has progressed the design of the reforms, the Commission has considered what possible changes might be required. The GRG may choose to build on this initial analysis as it progresses its work.

Changes to the NGL might, among other things:

- create an entity or entities to establish, operate and maintain the auction platform(s), and assign all the necessary statutory powers and functions required

144 See submissions on the discussion paper: PIAC, p. 6; APLNG, p. 4; QGC, p. 7; AGL, p. 2.

145 See submissions on the discussion paper: APGA, p. 19; APA, p. 14.

146 See submission on the discussion paper: AEMO, p. 9.

by the auction operator(s) to perform its role. Such powers and function might include to:

  - use confidential information and gather information from auction participants;
  - conduct the auctions including determining the optimum mix of products to be sold;
  - determine the results; and
  - collect payment and recover costs;

- empower the auction operator(s) to create procedures which govern the auction's design;
- create immunities for the auction operator(s);
- require shippers and pipeline owners (regardless of whether they are currently covered under the Gas Access Regime) to register under relevant NGR provisions;
- require pipeline owners to be subject to auction arrangements unless exempt (with the criteria for exemption set out in NGL);
- require pipeline owners to offer uniform service terms to auction participants; and
- set out information sharing requirements between the pipeline owners, shippers and the auction operator(s).

NGR changes might, among other things:

- provide further detail of the functions and powers of the auction operator(s);
- detail the various design features of the auction;
- set out registration requirements for auction participants; and
- specify the rights and obligations on the various parties participating in the auction (similar to the Short Term Trading Market rules in part 20 of the NGR).

Further detail of the auctions' design and operation might then be specified in subordinate documents, as considered appropriate by the GRG.

5.3 Standardisation of capacity products and contract terms

The contracts underpinning primary and secondary capacity trades on the east coast have historically been quite bespoke, with a range of terms and conditions customised to meet the requirements of the contracting parties. While the Commission understands that there may be value in customising the service related elements of these contracts, it can also see the value in implementing the following measures to make capacity products more fungible and, in so doing, facilitate a greater level of secondary capacity trading:

- Standardise the operational, prudential and other contract provisions that govern the relationship between the parties and their contractual obligations ('other contract provisions') in:
  - primary gas transportation agreements (GTAs) entered into between pipeline operators and shippers;
  - secondary capacity transportation agreements (CTAs) entered into between shippers; and
  - operational gas transportation agreements (Operational GTAs) entered into between pipeline operators and buyers of secondary capacity, which will be used to give effect to secondary trades that occur through the capacity trading platform and the capacity purchased through the auction.
- Standardising the secondary capacity products (eg standard contract path, capacity and tenor) that will be sold through the electronic exchange that the Commission recommends form part of the capacity trading platform exchange (see section 5.4.2).
- Provide shippers with greater flexibility to change receipt and delivery points.

The responses to the Stage 2 Draft Report and the Pipeline Access Discussion Paper were broadly supportive of the proposal to standardise some elements of CTAs.[147] Mixed views were, however, expressed about standardising GTAs, with some stakeholders noting that most pipelines already have standard GTAs and others claiming there is little value in standardising these contracts if Operational GTAs are available.[148] Other stakeholders, on the other hand, suggested it may be of value but greater priority should be given to standardising CTAs. With regard to receipt and delivery point flexibility, stakeholders were generally supportive of providing shippers

147 See for example, Secondary Submissions on Pipeline Access Discussion Paper: AGL, p. 3, APA, pp. 7-8, APGA, p. 10, Australian Energy Council, p. 2, Engie, p. 2, ERM Power, p. 2, Jemena, p. 2, Origin, p. 2, Santos, p. 2.

148 See for example, Submissions on Pipeline Access Discussion Paper: AEMO, p. 2, APGA, pp. 7-8, Epic, p. 4 and Origin, p. 2. Stanwell also suggested in its submission that if a bare transfer is used the terms in the CTA do not have to match those in the GTA and that it had been able to manage the risk exposure these differences can give rise to. Stanwell, Submissions on Pipeline Access Discussion Paper, p. 2.

greater flexibility[149] and for pipeline operators to be required to respond within a specified time.[150]

While there was some difference in opinion on this issue, stakeholders generally considered that standardisation should not be compulsory for GTAs and CTAs, or apply retrospectively to existing contracts.[151] Elaborating on this further, a large number of stakeholders suggested that bespoke service provisions are usually required by shippers to meet their specific end-use requirements and that if capacity products were completely standardised it could have broader reaching consequences for shippers.[152]

The ACCC also cited the benefits of standardising CTAs and GTAs in its east coast gas market Inquiry, which included reducing search and transaction costs and allowing trades to be executed faster.[153]

Having regard to the issues raised by stakeholders and the ACCC, the Commission remains of the view that steps need to be taken to make capacity products more fungible and tradable and that the standardisation and receipt and delivery point flexibility measures outlined above are appropriate. Together the Commission expects these measures to facilitate a greater level of secondary trade because they will:

- reduce search and transaction costs by making it easier for shippers to value and compare secondary capacity and reducing the provisions to be negotiated; and
- increase the pool of prospective sellers of secondary capacity by making it easier for primary capacity holders to change their receipt and delivery points and, in so doing, increase liquidity in the market.

5.3.1 Final recommendation

The Commission recommends that the COAG Energy Council agrees to the standardisation of key primary and secondary capacity contractual terms for each pipeline and for hub services, which where possible and appropriate apply these standards across the eastern Australian gas market.

Recommendation 6: *Standardisation of key primary and secondary capacity contractual terms for pipeline and for hub services, which where possible and appropriate apply across the eastern Australian gas market. Standards to be developed are for key operational, prudential and other*

149 See for example, Submissions on Pipeline Access Discussion Paper: AGL, p. 3, APLNG, p. 1 and Santos, p. 2.

150 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 9, Santos, p. 2, Epic, p. 3, Stanwell, p. 3.

151 See for example, Submissions on Pipeline Access Discussion Paper: AGL, p. 3, APA, p. 8, APGA, p. 7, Australian Energy Council, p. 2, Engie, p. 2, Epic, p. 2, ERM Power, p. 2, Origin, p. 2, Santos, p. 2, Stanwell, p. 3.

152 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 7, Epic, p. 2, ERM Power, p. 2, Origin, p. 2, Santos, p. 2, Stanwell, p. 3.

153 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 151.

contractual provisions in GTAs, CTAs and Operational GTAs, and provisions in contracts used for exchange based trading on the capacity trading platform. Counterparties to existing contracts should not be materially disadvantaged through the standardisation process.

The Council should agree to the development of required changes to the NGL and NGR and any other relevant instruments that are necessary to support the standardisation process, with the detailed design work being progressed by the GRG. Having market participants involved in the determining the appropriate level of standardisation and how to achieve greater receipt and delivery point flexibility is important because they are the ones that will ultimately have to operate under these terms and conditions.

In making this recommendation the Commission has included a number of required outcomes which must be progressed by the GRG. Other preferred outcomes that must also be considered by the GRG have also been progressed by the AEMC.

In terms of timing and prioritisation, it may, as some stakeholders suggested, be appropriate to prioritise the standardisation of CTAs, Operational GTAs and secondary capacity products for the electronic exchange. Once those standards are in place, consideration could then be given to standardising GTAs.

5.3.2 Standardisation - required outcomes

Standardisation of operational, prudential and other contractual provisions in GTAs, CTAs and Operational GTAs

The Commission is aware that shippers' end-use requirements can differ and that as a consequence the service related provisions in transportation contracts tend to be quite bespoke. While the Commission can see a continued role for customising these types of provisions in GTAs and secondary trades not conducted through the exchange developed as part of the capacity trading platform, there may be a case for standardising a number of other operational, prudential and other contractual provisions, regardless of the circumstance. Further detail on the difference between these types of provisions can be found in Box 5.3 overleaf.

Standardising operational, prudential and other contract provisions and, where feasible, developing common standards across pipelines (or compressors) and across contract types, will make it easier for shippers to trade capacity because fewer provisions will need to be negotiated. To the extent that standardisation can be achieved across pipelines then it will also remove any unnecessary impediments to trade across pipelines.

While the Commission is satisfied of the need to standardise these types of provisions, the form that these standards will take and the manner in which they are implemented will be a matter for the GRG to consider and recommend. The GRG will also be responsible for recommending whether common standards can be developed for all pipelines, or if pipeline specific standards are required.

At a minimum, the Commission would expect common standards to be developed for the prudential provisions, other contract provisions, and many of the operational provisions. It may, however, be more difficult to develop common standards for provisions that are more technical in nature, such as imbalance and overrun tolerance levels because they can depend on the physical characteristics and operating conditions of the pipeline.

Box 5.3 Different types of contract terms

A capacity holder's right to access pipeline or compression capacity will usually be defined by reference to the service related elements, which include:

- the type of service that the capacity is to be used for (eg transportation services (forward haul, backhaul or bi-directional), hub services or storage services);
- the firmness of the seller's obligation to provide the service (eg firm, as available or interruptible) and the priority in scheduling and curtailment;
- the receipt and delivery points (or zones) that services are provided between and any technical restrictions at those points (eg operating pressures); and
- the maximum capacity the shipper can nominate to be supplied at receipt and delivery points, which is usually measured on a daily and hourly basis and any renomination rights that the shipper may have.

The contracts will also contain:

- operational terms and conditions, such as
  - (a) start of gas day and nomination cut-off times;
  - (b) gas specification, gas quality and metering provisions;
  - (c) service definition and the priority accorded to firm, as available and interruptible services in the scheduling and curtailment processes;
  - (d) nomination, scheduling, curtailment and allocation procedures;
  - (e) imbalance, daily variance and overrun tolerance levels and penalties;
  - (f) the process for making changes to receipt and delivery points; and
  - (g) provisions relating to transfers, assignments and novations of capacity;
- prudential requirements; and
- other contract provisions, such as warranties, representations, possession, responsibility, title, control, liability and indemnities, default, force majeure, confidentiality and dispute resolution provisions.

Some other matters the GRG will need to consider in this context include whether:

- a single standard can be developed for each term and condition or if a range of standards may be more appropriate in some circumstances;
- a credit support mechanism should be developed to manage the risk to one counterparty when the other counterparty has low credit worthiness because this would no longer be managed through bespoke prudential requirements;
- changes need to be made to the allocation agreements[154]that shippers have entered into at some delivery points to enable capacity to be traded; and
- the adoption of these standardised provisions should be compulsory, or if shippers and pipelines should be able to negotiate around any provisions.[155]

These issues were discussed in the Pipeline Access Discussion Paper and many of the responses suggested that the list of operational, prudential and other contract provisions identified in the Discussion Paper as being capable of being standardised seemed reasonable, subject to detailed design.[156] There was also broad support for standardising provisions across pipelines where it is feasible, although a number of pipeline operators suggested that physical and operational differences across pipelines can limit the ability to harmonise some provisions.[157]

Although most stakeholders thought that standardisation should not be compulsory, Engie suggested that a regulatory mechanism be put in place to ensure any departure from a standard contract is justified.[158] Stanwell, on the other hand, suggested that standardised contracts developed in the electricity market had not been made compulsory and that shippers should have an incentive to use standardised provisions where it makes sense for them to do so.[159]

Standardisation of services for exchange traded secondary capacity products

To maximise the potential pool of buyers and sellers of secondary capacity via the exchange that will form part of the capacity trading platform, some degree of standardisation will be required across the following service dimensions for exchange traded secondary capacity products:

- type and firmness of the service;

154 Allocation agreements may be entered into by shippers using a common receipt point or delivery point and define how the gas delivered on a day is to be allocated between the shippers.

155 In the US, pipelines are not generally allowed to negotiate the non-price terms and conditions of access, but if a change is negotiated then the GTA must be submitted to FERC for approval. See Order 637 (2000).

156 See for example, Submissions on Pipeline Access Discussion Paper: APLNG, p. 1, Epic, p. 2, ERM Power, p. 2, Santos, p. 2, Stanwell, p. 3.

157 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 7 and APA, p. 8.

158 Engie, Submission on Pipeline Access Discussion Paper, p. 2.

159 Stanwell, Submission on Pipeline Access Discussion Paper, p. 2.

- points between which capacity will be provided (contract path);
- capacity to be made available (including any trading rights that may be required for trades involving supply to an STTM); and
- contract length.

Standardising these service dimensions, along with the operational, prudential and other contractual provisions in CTAs and Operational GTAs will result in more fungible capacity products that are capable of being traded through an exchange.

Many of the responses to the Pipeline Discussion Access Paper acknowledged the need for the service related dimensions of secondary capacity products to be standardised if exchange trading is implemented.[160] A number of stakeholders suggested, however, that the degree of standardisation required for these trades should be established through industry collaboration.[161]

The Commission agrees with stakeholders that industry should be involved in defining the scope of standardisation for exchange traded products and recommends this to occur through the GRG.

5.3.3 Standardisation - preferred outcomes

Receipt and delivery point flexibility

Capacity rights on contract carriage pipelines tend to be defined on a point-to-point basis by reference to specific receipt and delivery points that primary capacity holders have firm access rights to. While most GTAs allow primary capacity holders to change their receipt and delivery points, they are usually required to obtain the pipeline operator's consent before doing so. This consent can usually be withheld for commercial or technical reasons.[162] Some GTAs may also limit the number of changes that can be requested in a year, or otherwise limit the changes that can be made.

Non-technical restrictions on changes to receipt and delivery points can impede secondary capacity trade because they limit the pool of potential sellers of secondary capacity. It is for this reason that the Commission's preferred outcome is that shippers be provided with greater flexibility to change their receipt and delivery points. Through the consultation, a number of options for achieving greater flexibility have been discussed. The options that the Commission considers are likely to best achieve this objective are:

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160 Submissions on Pipeline Access Discussion Paper: AEMO, p. 3, Engie, p. 3, Origin, p. 3 and Stanwell, p. 5

161 Submissions on Pipeline Access Discussion Paper: Origin, p. 3 and Stanwell, p. 5.

162 A change may be rejected on technical grounds if there is insufficient capacity at the relevant point or if the change will affect another shipper's firm capacity rights.

- developing zones that cover multiple receipt and delivery points and allowing changes to occur relatively easily within these zones and putting in place rules that clearly define how changes across zones will be dealt with;
- only allowing pipeline operators to reject changes to receipt and delivery points on technical and operational (eg if the transfer would affect delivery to another shipper with firm rights) grounds, as opposed to commercial grounds; and
- requiring pipeline operators to respond to a request to change a receipt or delivery point within a specified time.

There may, however, be alternative approaches that could achieve a similar outcome more efficiently. The GRG should not therefore limit its consideration to these measures.

Stakeholders were generally supportive of the proposal to provide shippers with greater flexibility to change receipt and delivery points[163] and for pipeline operators to be required to respond within a specified time.[164] APGA and AEMO were the only stakeholders to comment specifically on the zonal model, both of whom supported this approach.[165]

In terms of the grounds on which pipelines should be able to reject changes, stakeholders were divided in their views, with shippers noting that it should be for technical reasons only, while pipelines considered it should be for technical and commercial reasons.[166] The commercial reasons pipeline operators cited include some that might be classified as operational reasons, such as not being able to meet another shipper's transportation requirements or renomination rights. APGA also suggested that pipeline operators should be able to reject changes that result in a reduction in revenue.[167]

In addition to these issues, APLNG and Santos raised concerns about the fees charged by pipeline operators to change receipt and delivery points, with Santos noting it is a "hindrance" to trade, while APLNG considered that changes should not be an additional source of revenue for pipelines.[168] A number of stakeholders also suggested

163 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 9, Santos, p. 2, Epic, p. 3, Stanwell, p. 3.

164 Submissions on Pipeline Access Discussion Paper: AEMO, p. 3, AGL, p. 3, APA, p. 9, APGA, p. 9, APLNG, p. 2, Australian Energy Council, p. 2, Origin, p. 2, PIAC, p. 4, Santos, pp. 2-3, Stanwell, p. 3.

165 Submissions on Pipeline Access Discussion Paper: AEMO, p. 3, APGA, p. 9.

166 See for example, Submissions on Pipeline Access Discussion Paper: AEC, p. 2, AGL, p. 2, Santos, p. 2 and Stanwell, p. 3.

167 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 9, APA, pp. 9-10 and Epic, p. 4.

168 Submissions on Pipeline Access Discussion Paper: APLNG, p. 2, Santos, p. 2.

that changes to allocation agreements[169]would be required to give effect to the changes.

The issues raised by stakeholders in this context should be considered further by the GRG.

5.3.4 NGL and NGR changes

As with the other secondary capacity trading reforms, it is likely that NGL and NGR changes and newly created subordinate instruments will be required to progress the capacity standardisation initiative.

The Commission has considered what possible changes might be required in this regard. The GRG may choose to build on this initial analysis as it progresses its work and makes recommendations to the COAG Energy Council and the AEMC.

Possible NGL changes include requiring all pipeline owners and shippers to enter into arrangements for the delivery and use of secondary capacity consistent with the standard service terms. The NGL might also require pipeline owners to publish and offer standard service terms for capacity bought through the auction platform or trading platform.

The NGR might need to be changed to set out the matters on which standardisation is required and any areas on which standardisation is not to be imposed (such as price) as well as the various design features for capacity standardisation (such as using a zonal model for receipt and delivery point flexibility). The NGR might also outline the governance for amending the capacity standards.

The capacity standards themselves might be documented in a subordinate instrument to the NGR. As discussed above, the standard terms and conditions could include (but not be limited to) terms addressing: service priority, nominations, scheduling, operational transfers, gas specification, gas pressure, interruptions, force majeure, safety, imbalances and defaults.

5.4 Capacity trading platform(s)

Although some steps have been taken over the last two years to better facilitate capacity trading,[170] there are, as stakeholders have pointed out in stages 1 and 2 of this review, still a number of factors that are limiting the ability of prospective shippers to access competitively priced secondary capacity, including:

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169 Allocation agreements may be entered into by shippers using a common receipt point or delivery point and define how the gas delivered on a day is to be allocated between the shippers.

170 For example, APA and Jemena both established capacity trading websites, which enable buyers and sellers of capacity (including the pipelines) to list bids and offers for capacity on their respective pipelines and to execute trades bilaterally using standardised terms and conditions. The Gas Supply Hub also includes a capacity listing service, which feeds directly into the Bulletin Board.

- A lack of information on the existence of prospective buyers and sellers of capacity, resulting in high search and transaction costs, particularly for short-term capacity trades. Buyers and sellers are unable to find each other, and so trades that would otherwise occur do not.

- Limited information on the market for both buyers and sellers, which may lead to additional costs as the parties attempt to understand the market value and determine whether they are being offered capacity on a non-discriminatory basis.

- Highly customised GTAs, which can make it difficult for participants to quickly and inexpensively determine the value of the capacity rights being sold in order to make a trade. Customisation also limits the liquidity of the market because a range of different products splits the market.

To address these issues, the Commission recommended in the Stage 2 Draft Report the mandatory development of a capacity trading platform(s) that would allow shippers to anonymously post buy or sell offers for secondary capacity up to the nomination cut-off time.

The responses from stakeholders to this proposal were generally positive,[171] although mixed views were expressed about some of the more detailed design elements. For example, shippers and PIAC advocated the adoption of a single platform that would sit alongside the Gas Supply Hub (and potentially the auction) and in doing so considered that it was the least cost option and offered the greatest co-ordination benefits because shippers would be able to obtain gas, hub and transportation services in one location. Pipeline operators, on the other hand, advocated the adoption of separate platforms operated by each pipeline operator. Differing views were also expressed about whether the platform(s) should provide for exchange based trading or a listing service, the types of services to be sold through the platform and if bilateral trades should be allowed to occur outside the platform.

The ACCC also made a number of observations about the proposed capacity trading platform in its east coast gas market Inquiry. Based on the feedback it received through the Inquiry, the ACCC considered the greatest benefits were likely to be gained if a single platform was developed for both the auction and capacity trading platform and for this platform to form part of the Gas Supply Hub, so shippers could obtain gas and transportation services in one centralised location.[172]

Having considered the issues raised by stakeholders and the ACCC, the Commission recommends that capacity trading platform(s) be developed and provide for both exchange based trading and a listing service. In short, the Commission expects that this initiative, in conjunction with the other three secondary capacity trading related initiatives, will better allow capacity trading by:

171 Submissions on Pipeline Access Discussion Paper: APA, p. 5, Jemena, p. 2 and APGA, pp. 12-13.

172 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 152.

- reducing search and transaction costs and the time taken to execute trades because:
  - shippers will be able to simply and anonymously post or review buy- or sell-offers on the platform(s), which will reduce search costs and speed up the transaction process;
  - capacity products will be more fungible and therefore capable of being readily valued and traded through an exchange; and
  - shippers will be able to quickly assess whether the price on offer is consistent with historical transactions;
- increasing liquidity through standardisation of secondary capacity products traded through the platform;
- improving the incentive primary capacity holders have to trade capacity, because in contrast to the auction, they will be able to retain the proceeds of any capacity sales carried out through the capacity trading platform; and
- providing shippers with confidence that future secondary trades are non-discriminatory, which when coupled with the anonymous nature of trading, will reduce perceived barriers to entry and enhance competition.

5.4.1 Final recommendation

The Commission recommends that the COAG Energy Council agrees to the creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms.

Recommendation 7: *Creation of capacity trading platform(s) which include electronic anonymous exchange based trading for commonly traded products in addition to a capacity listing service typical on current capacity trading platforms. Trades carried out through the capacity trading platform to be given effect through an operational transfer. For other secondary capacity trades, bare transfers will be allowed but the seller will be required to offer the buyer the option to use an operational transfer.*

The Council should agree to the development of required changes to the NGL and NGR and any other relevant instruments that are necessary to support the creation of the capacity trading platform(s), with the detailed design work being progressed by the GRG.

In making this recommendation the Commission has included a number of required outcomes which must be progressed by the GRG. Other outcomes would benefit from further consideration by the GRG and have been categorised as 'preferred' – the GRG should pursue these outcomes unless it is clear that there are greater benefits in alternative approaches. The Commission does not propose any 'suggested' outcomes.

5.4.2 Capacity trading platform(s) - required outcomes

Electronic exchange based trading and listing service

Trades executed through the capacity trading platform should occur via:

- an electronic exchange; and
- a listing service for more bespoke products.

An explanation of exchange based trading and a listing service is provided in Box 5.4.

Box 5.4 Electronic exchanges and listing services

An electronic exchange would allow shippers to anonymously submit buy or sell orders (bids or offers) for standardised capacity products and for those orders to be matched by the exchange. This is akin to the approach used in the GSH for gas trades and the PRISMA capacity trading platform in Europe.

In contrast, a listing service allows shippers to specify any capacity they wish to buy or sell and the price at which they are willing to do so. However, any decision to enter into a trade to be determined through bilateral negotiations rather than automatically. This is akin to the approach that APA and Jemena currently use on their respective capacity trading portals and the pipeline capacity listing service that has been built into the GSH.

For example, a shipper that had 100 TJ/day of firm capacity available for sale on the Moomba to Adelaide Pipeline System (MAPS) between Moomba and Adelaide for a 30 day period could sell this capacity through the electronic exchange because the service is relatively standardised in terms of the firmness of the service, the contract path, the capacity to be made available and the contract duration. A shipper that had 10 TJ/day of interruptible capacity available for sale on the MAPS between Moomba and Whyalla for a 12 day period, on the other hand, is more likely to use the listing service given the bespoke nature of the service.

In the Pipeline Access Discussion Paper, the Commission noted that it favoured the use of an electronic exchange for the majority of trades, particularly where the capacity being traded is standardised.

Stakeholders were divided in their opinion on whether trades executed through the capacity trading platform should occur via an exchange or listing service. For example:

- AEMO, ERM and APLNG suggested that an electronic exchange is required in order to improve on the existing listing service arrangements and considered that the current listing services have not been successful in selling capacity to date.[173]

173 Submissions on Pipeline Access Discussion Paper: AEMO, pp. 4-6, ERM, p. 2 and APLNG, p. 3.

- Jemena, APGA, Santos and Engie suggested a staged approach be adopted, with a listing service used initially and provision made to transition to exchange trading if greater demand emerges.[174]

- Origin suggested that any decision to require exchange based trading should consider the extent to which there is sufficient level of demand and a reasonable pool of standard products that can be sold.[175]

- Stanwell considered that an electronic exchange would be worth pursuing if the trading platform forms part of the Gas Supply Hub (because it costs little to add additional products to the existing system), but if it is run separately a listing service may be more appropriate given the costs of setting up a new exchange.

The Commission has examined the issues raised by stakeholders and agrees with AEMO, ERM and APLNG that the benefits that faster, non-discriminatory trading will have on market liquidity are likely to outweigh the disadvantages.

For this reason, the Commission recommends that the capacity trading platform provide for exchange based trading for standardised products and a listing service for more bespoke products.

While it is possible that demand may be limited in the early stages of the exchange's life, there are ways in which this can be managed. For example, the services to be sold through the exchange could be limited in the initial stages to the most popular contract paths to attract the most demand and other services could be sold via the listing service. As liquidity develops, the restrictions could be relaxed and other standardised products added to the exchange. Over time, as confidence in the exchange grows, the balance between capacity traded through the listing service and the exchange would be expected to shift. Another alternative that AEMO identified would involve allowing brokers to participate on the exchange.[176]

As to the cost of exchange based trading, the Commission understands the concerns that stakeholders have raised and notes that if the GRG recommends the capacity trading platform form part of the Gas Supply Hub, then the costs of running the exchange will be lower.

In order to implement this recommendation, the GRG will among other things need to consider:

- how the settlement, prudential and other operational aspects of the exchange based trading will work; and

- the contractual arrangements that will need to be put in place between primary capacity holders, buyers, pipeline owners and the exchange operator (were it to

174 Submissions on Pipeline Access Discussion Paper: Jemena, p. 2, APGA, p.11-12, Santos, p. 3, Engie, p. 4.

175 Origin, Submission on Pipeline Access Discussion Paper, p. 3.

176 AEMO, Submission on Pipeline Access Discussion Paper, p. 5.

be a different body that the pipeline owners), for both listed and exchange based trades.

Use of operational transfers in secondary trades

Historically, the Commission understands that most capacity trades executed in the east coast have been given effect through bare transfers, but operational transfers are starting to be used by parties using the APA and Jemena capacity trading portals (see Box 5.5). Operational transfers are also the predominant way in which shorter-term capacity is traded through trading platforms in Europe and the US short-term capacity release program.[177]

For the reasons set out below, the Commission considers that trades executed through the capacity trading platform should be given effect through an operational transfer:

- From a buyer's perspective, the operational transfer will provide greater anonymity in terms of nominations and its use of the pipeline, which is likely to be of some importance if the buyer has purchased capacity from a competitor.
- From a primary capacity holder's perspective, the operational transfer will alleviate it of the costs that it would otherwise incur in administering the trade and monitoring the buyer's compliance with various obligations,[178] which should encourage more primary capacity holders to sell any spare capacity they have.

For secondary capacity trades executed outside the capacity trading platform, bare transfers should be allowed but the seller should be required to offer the buyer the option to use an operational transfer. The Commission considers the option of an operational transfer is necessary because of the concerns some stakeholders have raised about having to submit nominations to potential competitors under bare transfers. It is also a more appropriate approach than prohibiting bare transfers because not all trades will involve a competitor and retaining this option may place a constraint on the price that pipelines can charge for operational transfers. Trading parties may therefore be able to use bare transfers for off-platform trades, as long as the seller also offers buyers the option of an operational transfer.

177 Brattle Group, *International Experience in Pipeline Capacity Trading*, 5 August 2013, pp. 10-11.

178 As outlined in Box 5.5, under an operational transfer the buyer makes nominations directly to the pipeline and compliance with operational and other contractual provision obligations will be a matter for the buyer and pipeline. The administrative and monitoring costs should therefore be much lower for the primary capacity holder under this type of trade.

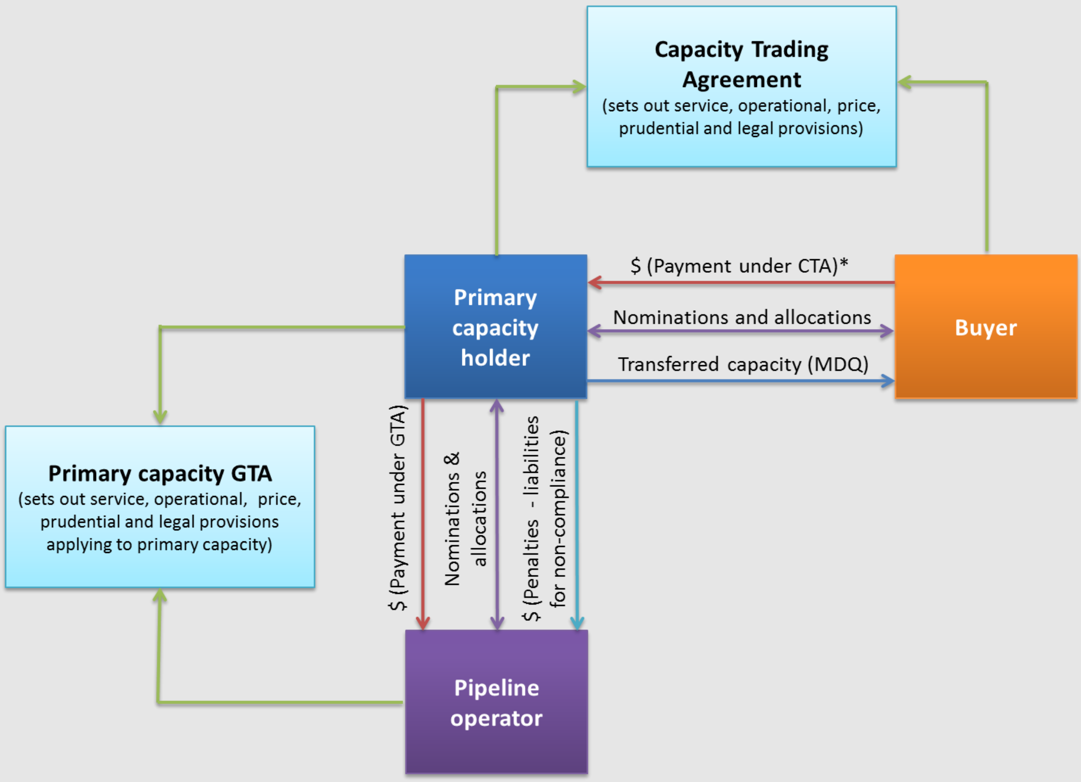
Box 5.5 Bare Transfers vs Operational Transfers

From a contractual perspective, the differences between a bare and operational transfer can be summarised are as follows:

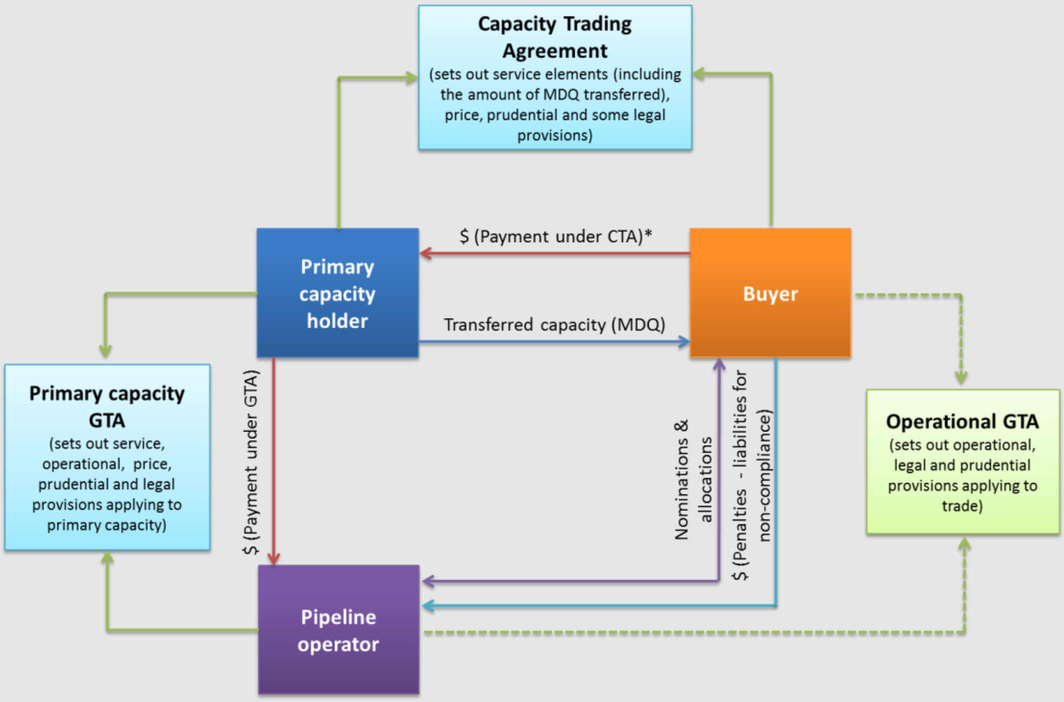
- Bare Transfer: Under this transfer mechanism all the terms and conditions applying to the trade are set out in an agreement between the primary capacity holder and the buyer (the CTA).
- Operational transfer: Under this transfer mechanism, the service, price and prudential provisions are set out in the CTA but the operational terms and the pipeline related prudential and other contractual provisions are set out in the Operational GTA between the pipeline operator and buyer.

The figures below set out how the contractual, financial and operational elements of these two types of transfers work.

Bare Transfer



Operational transfer



*Note the price paid under the CTA will not necessarily be the same price specified in the primary capacity GTA.

As these figures show, under both types of transfers, the primary capacity holder's capacity rights (or part thereof) are temporarily transferred to the buyer and the obligation to pay remains with the primary capacity holder. The key difference between these two forms of transfers is that:

- under the bare transfer, the primary capacity holder is responsible for:
  - Making nominations on behalf of the buyer of the secondary capacity.
  - Complying with the operational and legal obligations imposed by the pipeline under its GTA.
- under the operational transfer, the *buyer of the secondary capacity* is responsible for making nominations and complying with the operational and legal obligations imposed by the pipeline in the Operational GTA.

The operational transfer therefore results in lower administrative and monitoring costs for the primary capacity holder and greater anonymity for the buyer. Operational transfers can also impose costs on pipelines, which they may recoup.

Most of the responses to the Pipeline Access Discussion Paper supported the use of operational transfers for the capacity trading platform,[179]with the exception of QGC who preferred bare transfers to be the standard mechanism. One of the factors that QGC cited in support of is position, which AEMO also noted, is that operational transfers can add further costs to the trade because pipeline operators charge fees for this service.[180]For off-platform trades, AEMO and a number of shippers considered that bare transfers should be allowed.[181]

The views expressed by stakeholders in this context are broadly in line with the Commission's recommendations. Given the concerns raised by QGC and AEMO, however, it may be relevant for the GRG to consider whether the prices charged for operational transfers that will be used to facilitate trades on the capacity trading platform should be published.

5.4.3 Capacity trading platform(s) - preferred outcomes

Single capacity trading platform

In the Pipeline Access Discussion Paper the Commission noted the potential for either:

- a single capacity trading platform to be developed and operated as part of the Gas Supply Hub or on a stand-alone basis; or
- multiple trading platforms to be developed, with each pipeline operator to develop and operate their own platform.

The Commission also noted that a single capacity trading platform that covers all contract carriage assets would be more consistent with its objective of, where possible, harmonising the trading arrangements across the east coast. It was also noted that the Gas Supply Hub option was likely to offer a number of benefits over a stand-alone platform, including:

- shippers being able to co-ordinate their gas, hub services and transportation requirements through one platform, supporting the development of the Northern and Southern Gas Supply Hubs and attract liquidity in these hubs;
- shippers being subject to one set of prudential arrangements with any collateral posted for gas purchases being capable of being applied to capacity trades and vice versa;
- lower implementation costs for an exchange trade function because the IT systems, prudential, settlement and billing arrangements required to provide this function have already been established; and

179 Submissions on Pipeline Access Discussion Paper: AEMO, p. 3, APA, p. 7, APLNG, p. 2, APGA, p. 10, Epic, p. 4, Origin, p. 2 and Santos, p. 2.

180 QGC, Submission on Pipeline Access Discussion Paper, p. 4.

181 Submissions on Pipeline Access Discussion Paper: QGC, p. 4 and AEMO, p. 3.

- facilitate more effective competition between shippers that are offering to sell capacity on either the same transportation route or on competing routes.[182]

Responses to the Pipeline Access Discussion Paper were divided on this issue, with shippers and PIAC advocating the adoption of a single platform forming part of the Gas Supply Hub and potentially operating alongside the auction,[183] while pipeline operators and APGA advocated multiple platforms.[184] AEMO also advocated a single platform and suggested that regardless of who operated the platform it would be beneficial to have pipeline operators involved in its development.[185]

The benefits that shippers cited in support of a single platform forming part of the Gas Supply Hub were similar to those identified above, while PIAC considered this option was more in line with the goal of achieving a liquid wholesale gas market.[186] APA and APGA, on the other hand, considered that individual platforms would be a lower cost option.[187]

The Commission prefers a single capacity trading platform due to the benefits outlined above and because it expects this would cost less to implement and operate over time, particularly given a number of pipeline operators do not currently have a trading platform in place and an electronic exchange will need to be developed.

However, given the potential for higher costs associated with a single platform (for example communication costs between pipeline owners and the platform), the Commission considers that this matter should be considered further by the GRG.

Were a single platform implemented, the GRG would need to give consideration to the degree of integration that will be required between the capacity trading platform and pipeline operator systems to allow the results of any trades to be communicated to pipeline operators.

The Commission can also see the benefit of having the capacity trading platform form part of the Gas Supply Hub, but further thought needs to be given by the GRG to whether this is feasible given pipeline operators will need to play an active role in facilitating the trades.

182 For example, a shipper trying to sell capacity between Moomba and Adelaide would compete with other shippers selling capacity on the MAPS and may also compete with shippers selling capacity on the SEAGas Pipeline if the buyer can access gas in either Moomba or Port Campbell.

183 Submissions on Pipeline Access Discussion Paper: AGL p. 2, APLNG, p. 3, EnergyAustralia, p. 6, Engie, p. 4, ERM Power, p. 2, Origin, p. 4, PIAC, p. 4, Santos, p. 3, Stanwell, pp. 4-5.

184 Submissions on Pipeline Access Discussion Paper: APA, p. 5, Jemena, p. 2 and APGA, pp. 12-13.

185 AEMO, Submission on Pipeline Access Discussion Paper, p. 6.

186 Submissions on Pipeline Access Discussion Paper: APLNG, p. 3, EnergyAustralia, p. 6, Engie, p. 4, ERM Power, p. 2, PIAC, p. 4, Santos, p. 3, Stanwell, pp. 4-5.

187 Submissions on Pipeline Access Discussion Paper: APA, p. 5 and APGA, pp. 12-13.

Services to be traded through the platform

In principle, the capacity trading platform could be used by capacity holders to sell a range of pipeline related services on a firm, as available or interruptible basis, including:

- transportation services, such as forward haul, backhaul or bi-directional services;
- hub services, such as compression and redirection services; and
- pipeline storage services, such as park services or park and loan services.

It could also, in principle, be used by pipeline operators to sell these services on a firm basis using any spare primary capacity they may have.

Most responses to the Pipeline Access Discussion Paper considered there to be value in allowing as many services as possible to be traded through the platform,[188] including, potentially spare capacity in storage facilities.[189] Divergent views were, however, expressed about whether as available and interruptible services should be traded, with AEMO and APA stating there was no value in trading these services, while Stanwell and ERM thought there was.[190] As to whether pipeline operators should be able to sell services, Stanwell raised the potential conflicts of interest if pipelines were to also operate the platform, but stated that if AEMO operated the platform they should be able to participate because this would add liquidity to the market.[191] APLNG, on the other hand, stated that only capacity holders should be able to use the platform.[192]

The Commission agrees with stakeholders that as many transportation services should be capable of being traded on the platform as possible. There may, however, be value in trying to avoid any unnecessary complexities, at least in the early stages of the development of the exchange trading component of the platform. This could be done by limiting the services that could be sold through the platform to firm pipeline transportation and hub services. As confidence in the exchange grows, these restrictions could be relaxed and other services added.

The Commission suggests that the GRG consider this option when determining what services should be traded through the platform.

Bilateral trades outside the platform

Despite wanting to encourage as much trade as possible to occur through the capacity trading platform to enhance liquidity, the Commission recognises that there may still be a role for bilateral trades outside the platform, and that forcing all trades through

188 Submissions on Pipeline Access Discussion Paper: AEMO, p. 5, APA, p. 6, APGA, p. 11, ERM, p. 2, Stanwell, p. 4.

189 AEMO, Submission on Pipeline Access Discussion Paper, p. 5.

190 Submissions on Pipeline Access Discussion Paper: ERM, p. 2 and Stanwell, p. 5.

191 Stanwell, Submission on Pipeline Access Discussion Paper, p. 5.

192 APLNG, Submission on Pipeline Access Discussion Paper, p. 2.

the platform may discourage some participants from trading. This could occur for a number of reasons, including:

- the fee to use the capacity trading platform or the operational transfer being viewed by potential trading parties as too high for one-off trades; and
- the prospective buyer does not have an Operating GTA in place with the pipeline operator and has insufficient time to enter into such a trade.

Nevertheless, the Commission remains concerned that allowing bilateral trades outside the platform does not guarantee non-discriminatory access to capacity. Counterparties could discriminate against one another, by choosing not to enter into a bilateral trade, or pricing that trade differently than would otherwise be the case. In this sense, allowing the continued use of bilateral trades may favour incumbents and prevent the entry of smaller participants that these reforms are designed to achieve.

To counter this potential, the Commission's preference is for any trades conducted outside the capacity trading platform to be advertised ahead of time on the capacity trading platform listing service so that other shippers have an opportunity to compete for this trade. The GRG will need to consider, however, how this will be implemented in practice and whether any exemptions may be appropriate.[193]

With the exception of a limited number of stakeholders, the responses to the Pipeline Access Discussion Paper supported the proposal to allow bilateral trades to occur outside the platform.[194][195]Most stakeholders did not, however, see the need for those wishing to sell capacity off platform to advertise the proposed trade ahead of time, because:

- they were not convinced that off platform trades would be discriminatory, or that any discriminatory behaviour would not otherwise be dealt with by the introduction of the auction and price reporting;[196]
- they considered it would be time consuming and add another layer of complexity, costs and uncertainty to trading and could therefore discourage trades;[197] or

193 In the US, exemptions are available when the capacity trade is for less than one month. See *Code of Federal Regulations*, Title 18, part 284.8a.

194 Submissions on Pipeline Access Discussion Paper: AEMO, p. 7, APA, p. 6, APGA, p. 14, ERM, p. 2, Origin, p. 3, QGC, pp. 4-5 and Stanwell, p. 5.

195 The one exception was PIAC, who considered that bilateral trades should not be allowed outside the platform. APLNG also raised the potential for bilateral trades to be discriminatory. See Submissions on Pipeline Access Discussion Paper: PIAC, p. 5 and APLNG, p. 3.

196 Submissions on Pipeline Access Discussion Paper: APA, p. 6, APGA, p. 13, ERM, p. 2. and Stanwell, p. 5.

197 Submissions on Pipeline Access Discussion Paper: ERM, p. 2 and Stanwell, p. 6.

- they considered that it could adversely affect other trades where secondary capacity is just one component (eg trades involving both capacity and commodity).[198]

The Commission recommends that the GRG investigate this issue further, although as noted in section 5.5 below, information on all trades must be published regardless of whether they are conducted through the platform or bilaterally.

5.4.4 NGL and NGR changes

As with the other secondary capacity trading reforms, it is likely that NGL and NGR changes and newly created subordinate instruments will be required to progress the capacity trading platform(s).

The GRG might recommend that the NGL be changed to assign a function to an entity or entities to establish, maintain and operate the platform(s).

The NGR might provide further detail about the trading platform(s) and the trading arrangements to be established, and set out market conduct rules, which create the rights and obligations on the market participants (similar to the Short Term Trading Market rules in part 20 of the NGR).

A trading agreement might be created and struck between the entity(s) running the trading platform(s) and market participants (similar to the GSH exchange agreement) which sets out matters such as participation terms, how bids and offers are to be made, matched, delivered and settled, and payment terms. The trading agreement might also define and lists the products to be traded.

5.5 Information on secondary capacity trades

The prices and other terms on which secondary capacity trades are struck are currently confidential. As a result, shippers have no way to determine whether the secondary capacity is being provided on a non-discriminatory basis, or if the prices they are offered are reasonable. To address this information gap, the Commission recommends that information on the prices struck in all secondary trades be published, along with information on the key terms that may have affected prices in those trades.

Stakeholder responses to the Stage 2 Draft Report and Pipeline Access Discussion Paper were broadly supportive of this recommendation, provided the anonymity of the counterparties is sufficiently protected.[199] The ACCC's east coast gas market Inquiry also pointed to the benefits of greater price transparency in this area and

198 ERM, Submission on Pipeline Access Discussion Paper, p. 2.

199 Submissions on Pipeline Access Discussion Paper: AGL, p. 3, APA, p. 10, APGA, p. 15, APLNG, p. 3, Australian Energy Council, p. 2, EnergyAustralia, p. 8; Energie, p. 6, ERM Power, p. 3, QGC, p. 5 and Stanwell, p. 6.

recommended the COAG Energy Council consider requiring the reporting of this information.[200]

Consistent with the views expressed by stakeholders and the ACCC , the Commission expects that greater transparency in this area will:

- aid the price discovery process for secondary capacity trades, and by doing so reduce search costs and expedite the transaction process;
- provide for the efficient allocation and use of capacity because shippers will be able to readily assess the market value of capacity and make informed decisions; and
- enable shippers to engage in more effective negotiations and provide them with the confidence that access is being provided on a non-discriminatory basis.

This initiative can also be expected to instil a greater level of confidence in the secondary market, which will, in turn, support the development of a more liquid wholesale gas market. The initiative can therefore be considered consistent with both the NGO and the COAG Energy Council's Vision, which is why the Commission is recommending this initiative be pursued and that the GRG be accorded responsibility for taking it forward.

5.5.1 Final recommendation

The Commission recommends that the COAG Energy Council agrees to the publication of information on secondary trades of pipeline capacity and hub services. The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties.

Recommendation 8: *Publication of information on all secondary trades of pipeline capacity and hub services. The information to be published is the price of the trade and any other information that might reasonably influence that price, taking into account measures to protect the anonymity of counterparties, and should occur at or shortly after the time the transaction is entered into.*

The Council should also agree to the development of required changes to the NGL and NGR and any other relevant instruments that are necessary to support the publication of this information, with the detailed design work being progressed by the GRG.

In making this recommendation the Commission has included a number of required outcomes which must be progressed by the GRG.

There is a clear trade-off between the benefits of wide information provision and the possible concerns with regard to protecting counterparties' commercial-in-confidence information and the cost of information provision. In determining the information

200 ACCC ,*Inquiry into east coast gas market*, April 2016, p. 153.

reporting and publication requirements, the GRG should have regard to these issues and make recommendations that appropriately balance these trade-offs.

The Commission does not classify any outcomes as preferred or suggested with regard to the information provision requirements initiative.

5.5.2 Information on secondary capacity trades - required outcomes

Information to be reported

The Commission recommends that the COAG Energy Council task the GRG with developing a reporting obligation that at a minimum will require the reporting of prices struck in secondary trades and the following contract terms:[201]

(a) the pipeline or compressor facility that will be used to provide the service;

(b) the type of service (eg transportation, storage or compression service) and the firmness and priority of that service;

(c) when the contract was entered into and the duration of the contract;

(d) the maximum capacity the shipper can nominate on a daily and hourly basis;

(e) the direction of the service and the receipt and delivery points between which gas will be transported, aggregated to a level sufficient to protect the anonymity of counterparties; and

(f) any additional flexibility the shipper may have under the trade, or restrictions it may be subject to, and, where relevant, any variations from standardised operational, prudential and other contractual terms that could affect the price.

At this stage, the Commission does not consider it appropriate that the names of counterparties should be published, in order to protect anonymity. The GRG might consider whether there are any benefits in the publication of names.

Most of the submissions to the Pipeline Access Discussion Paper broadly agreed with the proposal to report this type of information,[202] although Santos and Stanwell raised the potential for too much reporting discouraging parties from entering into trades.[203] The only other substantive concern that was raised by stakeholders is that the publication of receipt and delivery point information could reveal the identity of the

201 Other terms and conditions can also affect the price (for example, penalty charges, credit support and prudential requirements and other legal provisions), but tend to have less of an influence on price, which is a relevant consideration given that cost of collating and storing this information.

202 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 15, AGL, p. 3, APLNG, p. 3, ERM Power, p. 3, Jemena, p. 2, Origin, p. 3, QGC, p. 5, Stanwell, p. 7 and Submissions on Stage 2 Draft Report: Santos, p. 6, Stanwell, pp. 4-5, EnergyAustralia, pp. 4-5.

203 Submissions on Pipeline Access Discussion Paper: Santos, p. 3 and Stanwell, p. 7.

trading parties.[204] To prevent this from occurring some stakeholders suggested that parties only be required to report the pipeline name and direction of trade, or that receipt and delivery point information be aggregated to a zonal level.[205] APA, on the other hand, suggested that aggregation to a zonal level could obscure details that would assist price discovery.[206]

The Commission recognises that commercial-in-confidence information may be inferred from published information even if counterparties' names are not published. It is for this reason that the list above refers to receipt and delivery points being aggregated. The way in which receipt and delivery points should be aggregated to protect the identity of trading parties, while still providing for the disclosure of information that can have a direct bearing on price, will be a matter for the GRG to consider.

In addition to considering this issue, the GRG should also be responsible for considering whether any other measures are required to protect the anonymity of the trading parties, taking into account the relative benefits of information provision and anonymity.

Types of secondary trades to be reported

The Commission also recommends that the GRG be required to develop information reporting that applies to *all* secondary capacity trades from the date the obligation takes effect, regardless of whether the trades are carried out on a bilateral basis or through the capacity trading platform.

The responses to the Pipeline Access Discussion Paper were broadly supportive of the proposal to report secondary trades of pipeline and hub services.[207] Mixed views were, however, expressed about whether the obligation should apply to standardised and bespoke trades, with AEMO and APA supporting the reporting of both while Stanwell suggested limiting it to standardised trades. The reporting obligation should therefore apply to both standardised and bespoke trades of secondary transportation capacity (ie pipeline services and hub services).[208]

Excluding bespoke trades from the reporting obligation could distort trading decisions and undermine the development of a market for standardised capacity products because parties that want to avoid reporting will have an incentive to enter into bespoke trades outside of the capacity trading platform. It is for this reason that the Commission is recommending that the GRG is tasked to develop information

204 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 15, AGL, p. 3, APLNG, p. 3, ERM Power, p. 3, Jemena, p. 2, Origin, p. 3, QGC, p. 5, Stanwell, p. 7 and Submissions on Stage 2 Draft Report: Santos, p. 6, Stanwell, pp. 4-5, EnergyAustralia, pp. 4-5.

205 See for example, Submissions on Pipeline Access Discussion Paper: Origin, p. 3.

206 APA, Submission on Pipeline Access Discussion Paper, p. 11.

207 See for example, Submissions on Pipeline Access Discussion Paper: AEMO, p. 8, APA, p. 10, APLNG, p. 3 and Stanwell, p. 7.

208 Submissions on Pipeline Access Discussion Paper: AEMO, p. 7, APA, p. 10 and Stanwell, p. 7.

provision requirements that require that all secondary trades be subject to the same reporting requirements.

When information should be reported

Finally, the Commission recommends that the COAG Energy Council task the GRG to develop a reporting obligation that requires the prices and other key terms struck in secondary capacity trades to be reported at the time the trade is entered into, or shortly after. Reporting within this timeframe will aid the price discovery process for capacity trades and the auction process.

Most submissions to the Pipeline Access Discussion Paper agreed with this timing.[209] ERM Power did, however, suggest a less onerous reporting requirement for trades conducted outside a trading platform, with information to be reported on a monthly basis or after the contract has ended.[210]

Like Stanwell's suggestion to exclude bespoke trades, the concern the Commission has with ERM Power's suggestion is that it could distort trading decisions and encourage shippers to carry out trades outside the platform. The value of reporting information up to a month after the trade has occurred is also questionable from a price discovery perspective. The Commission recommends therefore that all secondary trades be subject to the same reporting time frame, regardless of how it is executed.

5.5.3 NGL and NGR changes

As with the other secondary capacity trading reforms, it is likely that NGL and NGR changes and newly created subordinate instruments will be required to progress the secondary capacity trading information reforms.

Depending on the design of the reform, the NGL could be changed to oblige counterparties of trades to notify to a specified entity information about the trades. That entity could be assigned responsibility through the NGL to aggregate the information to protect the anonymity of counterparties, and to present the information in a timely manner.

NGR changes could provide further detail about the obligation of counterparties to trades, and set out details relating to the information provision requirements and aggregation of information.

5.6 Primary capacity markets and the Gas Access Regime

Throughout this review, the Commission has also considered issues related to the primary capacity market (ie, capacity sold by pipeline owners to shippers). In

209 See for example, Submissions on Pipeline Access Discussion Paper: APGA, p. 15, APLNG, p. 3, ERM Power, p. 3 and Stanwell, p. 7

210 ERM Power, Submission on Pipeline Access Discussion Paper, pp. 3-4.

particular, some stakeholders consider that pipeline owners may be engaging in discriminatory[211] or monopoly pricing.

5.6.1 AEMC's draft recommendation to address actual or perceived discriminatory pricing

Non-discriminatory access to transportation capacity is critical if market participants are to be able to compete in upstream or downstream markets, while even the perception of discrimination may deter entry.[212] Actual or perceived discrimination can therefore inhibit competition in upstream or downstream markets, and thus limit the development of liquidity.

The price and other terms of primary capacity transactions are currently confidential, meaning that other shippers have no way to assess whether their own capacity purchases are non-discriminatory.

This may particularly deter new entry by shippers with smaller gas portfolios, who, unlike a large shipper, may consider that they do not have the market power to negotiate a good deal with the pipeline owner. Importantly, the perception of non-discriminatory access is as important as the practice of non-discriminatory access. Even if, in practice, shippers are being charged the same tariff for the same service, if they perceive that they are not receiving competitively neutral treatment relative to incumbents then this may be sufficient to deter new entry.[213]

In light of this, in the Stage 2 Draft Report the Commission recommended that the actual (not advertised) price of all primary capacity sales, and terms and conditions of those sales which might impact the price, should be published. To the extent that pipeline owners are currently price discriminating, transparent historical prices, terms and conditions should place a discipline on pipeline owners not to undertake this practice. Even if price discrimination is not occurring in practice, transparency should give shippers confidence that this is indeed the case, and improve their negotiating power with the pipeline owners.

5.6.2 Monopoly pricing by pipeline owners

At the time of the Stage 2 Draft Report, stakeholders had also raised concerns that pipeline owners were engaging in monopoly pricing (as distinct from anti-competitive discriminatory pricing). However, much of the evidence presented by stakeholders

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211 For example, see Pipeline Regulation and Capacity Trading Discussion Paper submission: Encana, p. 4.

212 Price discrimination occurs when different prices are charged for the same product. This does not mean that all pipeline capacity must be sold at the same price. There may be price differences due to differences in the products (ie short term versus long term products, or the same duration product at two different times). Also customers may pay different prices for the same product as a result of auction outcomes. Undue price discrimination arises where the same product is sold for a different price without any objective justification.

213 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 31.

was anecdotal in nature, reflecting a lack of information transparency within the market. A further benefit of the information provision recommendations made in the Draft Stage 2 Report is that it would enable regulators to better assess the prevalence of pipeline monopoly power.[214]

The AEMC was also aware that the ACCC was gathering evidence of potential issues in the primary capacity market utilising its compulsory information gathering powers under the Competition and Consumer Act (2010). Consequently, while not making any recommendations regard the economic regulation of pipelines to address monopoly pricing at that time, the AEMC noted that in the event that the ACCC were to find that there are issues to be addressed in relation to the incentives acting on pipeline owners – or in relation to the ability of the current regulatory regime to act as an effective constraint on these – the Commission may look to supplement its draft recommendations.[215]

Since the release of the AEMC's Stage 2 Draft Report, the ACCC published its report which discussed evidence that it has gathered which suggests that a large number of pipeline owners are using market power to engage in monopoly pricing. Furthermore, the ACCC found that the current Gas Access Regime is not acting as an effective constraint on this behaviour.[216]

As a result of these findings, the ACCC has recommended to the COAG Energy Council that[217]:

- the current test for regulation of gas pipelines (the coverage test) in the Gas Access Regime in NGL be replaced in order that it better addresses the issue of market power and monopoly pricing;
- the AEMC should carry out further consultation and advise the COAG Energy Council of the suitable amendments to the test;
- the AEMC should also review relevant aspects of the NGR and make any amendments that may be required to address the concern that the owners of pipelines subject to regulation are nevertheless able to exercise market power; and
- the AEMC should explore whether the scope of the information disclosure requirements for pipeline owners in the NGL should be expanded, to enable shippers to negotiate more effectively with pipeline owners and for the exercise of market power to be more readily identified.

214 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report, 4 December 2015, pp. 71-72.

215 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 2 Draft Report, 4 December 2015, p. 53.

216 ACCC, *Inquiry into east coast gas market*, April 2016, chapters 6 and 7.

217 ACCC, *Inquiry into east coast gas market*, April 2016, p. 20.

The ACCC’s findings with regard to the Gas Access Regime are consistent with analysis undertaken by the AEMC in this review. Following the release of the Stage 1 Final Report, the Commission published the Pipeline Regulation and Capacity Trading Discussion Paper[218] and two reports that it had commissioned from Castalia[219] and Incenta[220], which examined the appropriateness of the test for regulation under the Gas Access Regime.

In the discussion paper, the Commission noted that the Gas Access Regime is not a comprehensive regulatory instrument designed to solve a broad range of problems such as monopoly pricing and that if such behaviour was occurring pipelines may not be subject to the appropriate level of regulation. Unconstrained by competition or regulation, pipeline operators may be able to price capacity at a level higher than that which would be expected to prevail in a workably competitive market, which could have a detrimental effect on economic efficiency and consumers more generally, against the interests of the NGO.

Given the ACCC's analysis and evidence of the problem, which is consistent with the AEMC's own analysis, the AEMC concurs with the ACCC's recommended approach to progressing reforms to the Gas Access Regime. The AEMC further notes that moves to make a more industry specific access regime for gas in the manner envisaged by the ACCC is not inconsistent with the approach taken in some other sectors – indeed, the electricity sector is a clear example of an industry specific access regime.

Given the high degree of consistency between the ACCC’s recommendation with regard to information disclosure requirements and the AEMC’s draft recommendation for the publication of price and price related information for primary capacity sales, the AEMC recommends that the appropriate information provision requirements in the primary market be further considered if the COAG Energy Council agrees to pursue the ACCC’s recommendation.

If the COAG Energy Council agrees to progress a review of the primary capacity market, the AEMC does not consider that this should delay the progression of recommendations 5 to 8 relating to the secondary capacity market.

218 AEMC 2015, *East Coast Wholesale Gas Market and Pipeline Frameworks Review: Pipeline Regulation and Capacity Trading Discussion Paper*, 18 September 2015.

219 Castalia Strategic Advisers, *AEMC Gas Access Regime Advice*, 10 August 2015.

220 Incenta Economic Consulting, *Assessment of the coverage criteria for the gas pipeline access regime*, September 2015.

6 Information and the Bulletin Board

Box 6.1 Recommendations and summary of chapter

Wholesale gas and pipeline markets should be underpinned by arrangements to allow participants ready access to the information they require to make informed decisions. To address current informational gaps and asymmetries identified through the review, the Commission has developed a detailed package of recommendations to improve the operation and relevance of the Bulletin Board for participants in the east coast gas market. As set out in out in a supplementary report, the package comprises improvements in the following areas:

- broadening the stated purpose of the Bulletin Board;
- improving the reporting framework, to allow all relevant facilities to report and simplifying the registration provisions;
- strengthening the compliance framework;
- expanding the coverage of the Bulletin Board to include additional information on reserves, compression and large users;
- exempt facilities that are not connected to the east coast market from registration and reporting;
- improve existing reporting requirements, including by increasing the frequency with which some information is reported;
- facilitating the publication of information on a disaggregated, as well as aggregated, basis;
- improving the information on market pricing and adding links to other useful information;
- removing pipeline operator cost recovery provisions from the NGR;
- removing the cost recovery provisions for AEMO's Bulletin Board activities from the NGR; and
- introducing a biennial process for AEMO to report on the operation of the Bulletin Board and any required changes.

Recommendation 9: *Improvements should be made to the Natural Gas Services Bulletin Board to enhance the breadth and accuracy of information provided to the market, as detailed in recommendations A-K of the East Coast Wholesale Gas Market and Pipeline Frameworks Review Stage Final Report: Information Provision.*

Enhancements to the scope, accuracy and timeliness of information are expected to promote allocative efficiency by allowing trading decisions to be based on more complete, accurate and timely information. Better decision making and greater participation on trading markets is likely to lead to more meaningful and robust market prices, which should in turn provide participants with transparent signals for investment in gas infrastructure, promoting dynamic efficiency.

6.1 Introduction

An important characteristic of a workably competitive market is that participants have ready access to the information they require to make informed decisions. In gas markets, such pricing expectations are not formed in relation to one specific data point but require a range of information about consumption, gas supply, transportation, storage, risk management, planning and investment in both the short- and long-run. If this characteristic is missing from a market and decisions have to be made on the basis of incomplete, inaccurate, dated or asymmetric information, it may result in an inefficient allocation of resources both in the market and the broader economy.

The east coast gas market has historically operated in an opaque manner with gas, transportation, storage and risk management services sold under bilateral contracts that have invariably been treated as confidential by the parties. Information on some key demand and supply fundamentals in the market has also tended to be opaque.

In response, the Natural Gas Services Bulletin Board was created in mid-2008 to provide a more level playing field by requiring certain information be provided to a central repository for use by all market participants and the public. Since its inception, the gas market has become more dynamic. As a result, timely and accurate information to inform operational and commercial decisions, as well as policy decisions, has become more important.

In Stage 1 of this review, stakeholders raised a number of concerns about the level of reliance that can be placed on the information reported on the Bulletin Board and the information gaps and asymmetries present in the market. The Commission formed a similar view in the Stage 1 Final Report, which noted that there are "some gaps and asymmetries that may be affecting the efficiency with which gas and other resources are allocated in the market and across the economy".[221]

In Stage 2 of this review the Commission has focused on improvements that could be made to the Bulletin Board to instil a greater level of confidence in the reported information and address information gaps and asymmetries, in particular with the aim of establishing it as a 'one-stop-shop' for information on the east coast gas market.[222] In doing so, the Commission has had regard to the national gas objective (NGO). Relevant information will support gas use and allocation decisions over the short- and long-term, leading to the efficient use of and investment in gas for the long-term interests of consumers. This is consistent with the NGO.

The Commission has also had regard to:

- the Council of Australian Governments (COAG) Energy Council's Australian Gas Market Vision (Vision);

221 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, p. 159.

222 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, p. 176.

- the findings and recommendations contained in the Australian Competition and Consumer Commission's (ACCC) Inquiry into the east coast gas market; and;
- submissions and other information received from stakeholders.

To address the current informational gaps and asymmetries identified through the review, the Commission has developed a detailed package of improvements to enhance the operation and relevance of the Bulletin Board for participants in the east coast gas market. This chapter provides a summary of these recommendations, as well as discussing how these align with the findings of the ACCC inquiry.

The package of recommendations is set out in full in a supplementary report, which also contains a more detailed explanation of the Commission's reasoning.[223]

6.2 Bulletin Board reporting model

The confidence of market participants in the information reported on the Bulletin Board will depend on the extent to which the reporting model that underpins it provides for an accurate and timely picture of gas supply, pipeline flows, storage and demand. The Commission's assessment is that some elements of the reporting model are limiting the reliance that can be placed on information reported on the Bulletin Board. One of the more significant limitations with this model, is that it does not currently capture all of the facilities required to satisfy the Bulletin Board purpose and can result in delays in new facilities registering and reporting. The absence of a clear information standard and gaps in the compliance framework are also affecting the confidence that users can place on the Bulletin Board.

To address these limitations and instil a greater level of confidence in the Bulletin Board, the Commission's final recommendations are:

- **Recommendation A:** Broaden the stated purpose of the Bulletin Board to recognise the important role that information plays in enabling informed and efficient decision making, as well as aiding price discovery and facilitating trade.
- **Recommendation B:** Improve the reporting framework by:
  - Removing the link that currently exists between the obligation to report and the zonal model.[224]
  - Simplifying the exemption criteria and reducing the minimum reporting threshold to 10TJ/day for transmission pipelines, production facilities, storage facilities, compression facilities used in the provision of hub

223 AEMC, *East Coast Wholesale Markets and Pipelines Frameworks Review*, Stage 2 final report: information provision, July 2016.

224 The NGR requires AEMO to use a zonal model (with production and demand zones defined in the Procedures). This model determines the registration of parties and the reporting and publication of information.

services in the Gas Supply Hub (GSH compression facilities) and large user facilities.

- Removing the existing distinction between facilities commissioned pre- and post-1 July 2008.
- Redrafting the registration provisions to provide greater clarity about who is required to register, when registration is required and the interaction between registration and reporting.
- Introducing an information standard for all facilities to employ and classifying the obligation to comply with this standard as both a civil penalty and conduct provision.

- **Recommendation C:** Strengthen the compliance framework by classifying the obligation to register as a civil penalty provision. Notes should also be added to the relevant rules to identify those that are civil penalty or conduct provisions.

6.3 Reporting requirements

Stakeholders, the COAG Energy Council and the ACCC have noted that there are a number of significant information gaps and asymmetries across the gas market. In part this arises from reporting obligations only applying to producers, certain transmission pipelines and storage facilities. These gaps can be expected to adversely affect the price discovery process and the way in which gas and other resources are allocated because trading and other decisions must be made on the basis of incomplete, inaccurate and/or asymmetric information.

To address the informational gaps and asymmetries, the Commission's final recommendations include the following improvements to the Bulletin Board:

- **Recommendation D:** The entities that are required to report Bulletin Board information to AEMO should be expanded to include:
  - The operators of gas fields with proved and probable (2P) reserves – to report 2P reserves on an annual basis (or more frequently if a revised estimate is subsequently reported to the ASX or a government agency).
  - The operators of GSH compression facilities – to be subject to similar reporting obligations as operators of pipelines.
  - Large users – The operators of large user facilities (including LNG facilities) are to report the nameplate capacity of their facilities and daily consumption. The operators of LNG facilities to also report on their facility’s short- and medium-term capacity outlook and material intra-day capacity changes.[225]

[225] A large user facility does not include a retail business.

- **Recommendation E:** Exempt facilities that are not connected to the east coast market from registration and reporting requirements until such time as they are connected. The exempt facilities include those in the Northern Territory and those located in north Queensland near Moranbah and Townsville.

- **Recommendation F:** Amend the existing reporting requirements to:

  — Require those facilities that report on their medium-term capacity outlook to also report on planned expansions and asset retirements.

  — Improve the frequency with which information is reported and alerted to the market in regard to material intra-day changes to a facility's capacity or nominations, with information to be reported as soon as practicable on the gas day.

  — Require pipeline operators to report nominations and forecasts on both a receipt point (injection) and delivery point (withdrawal) basis.

  — Require producers to report nominations and forecasts for production facilities.

  — Remove the obligation for AEMO to publish estimates of the total forecast demand on peak demand days.

6.4 Publication of information on the Bulletin Board

The existing Bulletin Board rules require the use of a zonal model to aggregate, report and publish pipeline flow information. This has resulted in some significant information gaps to emerge over time as the zonal model has not been sufficiently flexible to reflect changes in the market. To address these issues, the Commission recommends:

- **Recommendation G:** That AEMO be responsible for the aggregation of information to be published on the Bulletin Board and that:

  — BB pipelines must report actual flows, nominations and forecast information on a disaggregated basis, by receipt and delivery point; and

  — AEMO must publish its aggregation methodology in the Procedures.

Under this recommended approach different types of information would be published at different times:

- Pipeline nomination and forecast information would be aggregated and published without delay. This information would not be published in disaggregated form because aggregated information is sufficient to provide an overview of expected gas flows. In addition, it may have competitive impacts for gas fired generators in the NEM.

- Pipeline receipt and delivery point actual flows would be aggregated and published on the following day to provide an overview of actual flows around the market. It would also be published in a disaggregated form. The Commission has not identified any competitive impacts from the publication of actual gas flows on the following day.
- Large user actual gas use data would be published on the following day. The Commission has not identified any competitive impacts from the publication of actual gas flows on the following day. In addition, AEMO would aggregate large user gas use to provide an overview of different types of demand across the market (for example, by user type).

The Commission has also identified a number of actions that could be undertaken by AEMO in its capacity as the Bulletin Board operator that go to addressing some of the concerns raised by stakeholders. These actions do not require any change to the NGL, Regulations or NGR.

- **Recommendation H:** That AEMO progress actions under the current framework to:
  - adopt a fixed and consistent standard for the assumed direction of bidirectional pipelines;
  - improve the information on the Bulletin Board related to pricing;
  - provide a notice board to allow market participants to notify each other of opportunities; and
  - add links to government and industry reports related to upstream activities and other gas market activities (as an interim measure until that information is provided directly by participants).

6.5 Funding arrangements and future development

Provisions in the NGR currently allow pipeline operators to recover the costs that they incur in providing 'aggregation and information services' to AEMO although these provisions have not been used to date. As a result of other recommendations in this report, pipeline operators will no longer be providing these services. In addition, the burden of providing information will increasingly be shared by more gas market participants. Given these changes, the Commission recommends that:

- **Recommendation I:** The pipeline operator cost recovery provisions be removed from the NGR.

The NGR also sets out the methodology that AEMO is to employ to recover its Bulletin Board costs. However, this is inconsistent with the arrangements in place for other AEMO activities. In addition, the level of prescription in the NGR has resulted in very little flexibility for AEMO to adjust its fee methodology to changing market circumstances. The Commission considers that the inconsistent governance approach is unwarranted and AEMO should be able to incorporate its Bulletin Board costs into its broader fee methodology process. This view has been supported by a number of stakeholders. Accordingly, the Commission recommends:

- **Recommendation J:** The cost recovery provisions for AEMO's Bulletin Board activities be removed from the NGR.

During this review a number of stakeholders have expressed concern that the Bulletin Board has had limited amendments made to maintain its relevance to the east coast gas market and to meet the needs of market participants. The Commission acknowledges this wide-spread concern. To address these concerns and to provide a framework to assist in the ongoing relevance of the Bulletin Board, the Commission considers a periodic report would aid in the identification of minor issues and potential procedure changes as well as potential rule change requests or more substantial concerns that may be considered by the COAG Energy Council. Consequently, the Commission recommends:

- **Recommendation K:** AEMO be required to publish a biennial report on the operation of the Bulletin Board and any potential changes required. The report is to be prepared in consultation with Bulletin Board users, the AER and the AEMC.

6.6 Alignment with the ACCC inquiry

The ACCC's inquiry into the east coast gas market was completed in late April 2016. The final report raised a number of concerns about the opaqueness of the east coast gas market and the quality of some information. The ACCC noted that the lack of transparency and information surrounding gas reserves, the utilisation of regional pipelines, commodity and transportation prices is:[226]

> "... hindering efficient market responses to the changing conditions and are not signalling expected supply problems effectively."

To address these informational deficiencies, the ACCC recommended that:[227]

- all explorers and producers be required to report consistent 2P reserves and resources and for this information to be published on the Bulletin Board;
- information on the capacity and utilisation of regional pipelines be published on the Bulletin Board;
- information relating to gas prices should be made available, specifically recommending that:

226 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 19 and 154.

227 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 20-21 and 154.

— the AEMC consult with gas users about the potential benefits of a periodic price series of actual commodity gas prices paid to producers, either for the east coast generally or for Victoria and Queensland;

— AEMO develop and publish a monthly LNG netback price to Wallumbilla; and

- the AEMC consider how the information disclosure provisions in the NGL could be expanded to require greater transparency around primary and secondary capacity trades and the costs incurred by pipeline operators in the provision of services.

The last of these recommendations is discussed in further detail in Chapter 5.

In relation to the first two recommendations, the Commission agrees with the ACCC's observations on the need for greater transparency around 2P reserves and regional pipelines, and its recommendations in this area are largely aligned with those of the ACCC. The only areas where the Commission has not gone as far as the ACCC recommended is the proposal to require:

- common price assumptions to be used in the calculation of 2P reserves – this proposal was raised too late to consult with stakeholders on and so will be considered as part of the rule change process that follows this review; and

- contingent or prospective resources[228] to be published on the Bulletin Board – in this case the Commission suggests that the 2P reporting requirement be bedded down before requiring resources to be reported, given it is more speculative in nature than 2P reserves.

In relation to the proposal that the AEMC consult on the potential benefits of a periodic price series, the Stage 1 Draft Report tested the idea of publishing a price level index based on a survey of market participants' expectations in order to resolve the lack of transparency around forward gas prices. Feedback through stakeholder submissions pointed to a number of issues with this approach, such as the potential for the index to be manipulated and the risk of crowding out commercial entities which may be better placed to produce this service (ie Argus and Platts).[229]

Instead, the Commission recommended working with the Australian Bureau of Statistics (ABS) to establish a survey-based gas price index (similar to the CPI) to measure the trends in prices payable under bilateral contracts over time. The ABS index will be compiled based on the prices paid under existing contracts using

228 Contingent resources are quantities of natural gas estimated to be potentially recoverable from known accumulations but are not yet considered able to be developed commercially due to one or more contingencies. Prospective resources are estimated quantities associated with undiscovered natural gas. These represent quantities of gas which are estimated, as of a given date, to be potentially recoverable from gas deposits identified on the basis of indirect evidence but which have not yet been drilled.

229 AEMC 2015, *East Coast Wholesale Gas Market and Pipeline Frameworks Review*, Stage 1 Final Report, 23 July 2015, Chapter 8.

well-established data collection processes and index calculation methodologies used by the ABS. Movements in the index will provide transparency around the direction and magnitude of movements in average prices in bilateral gas contracts.

As discussed in Appendix D, the ABS is currently collecting data from gas market participants and expects to first publish the index in early 2017. The Commission intends to review the adequacy of this measure as part of its recommended biennial reviews of gas market liquidity (see Appendix F). If the measure is found not to have met its objective of increasing transparency around price movements in GSAs, then the Commission will undertake consultation with industry on additional transparency measures that may be appropriate, including on the ACCC's suggested approach.

The ACCC also recommended that AEMO develop and publish a monthly LNG netback price to Wallumbilla, which the Commission notes is likely to contribute to increased transparency around prices in the wholesale gas market.

A Terms of Reference

Background

Australian gas markets are experiencing a rapid transition as conventional gas reserves decline, unconventional gas resources become increasingly important, pipeline and storage infrastructure improves, and the influence of international price trends increase. The establishment of a liquefied natural gas (LNG) export industry based in Queensland is triggering a structural shift in supply and demand, and will lead to significant changes in the pattern and direction of gas flows.

These factors are driving a period of adjustment in the market as uncertainty around future gas prices increases. This is also leading to a renewed focus on market development and the efficiency of the gas supply chain. In particular, the establishment of well-functioning markets (commodity, financial and transportation) is key to promoting the most efficient use of gas, in the long term interests of consumers.

In light of these changing dynamics, the AEMC's 2013 Gas Market Scoping Study highlighted the fragmented nature of gas market development and identified a range of potential issues that may be affecting the efficient operation of the market. Other reviews such the Australian Government's Eastern Australian Domestic Gas Market Study and the Victorian Government's Gas Market Taskforce have also identified areas for reform.

At its December 2014 meeting, the Council of Australian Governments (COAG) Energy Council outlined its vision for Australia's future gas market:

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

This vision is underpinned by the Gas Market Development Plan, which outlines actions the COAG Energy Council will initiate to improve Competitive Supply, Transparency and Price Discovery, Risk Management, and Removing Unnecessary Regulatory Barriers.

In order to assist the Council realise its vision, it is tasking the AEMC to review the design, function and roles of facilitated gas markets and gas transportation arrangements.

The Council, at the request of the Victorian Government, has separately tasked the AEMC to review the Victorian Declared Wholesale Gas Market (DWGM). The two reviews are related in scope and timing, as such the Council expects the findings of the

DWGM review will be incorporated in the East Coast Wholesale Gas Market and Pipeline Frameworks Review.

Purpose of the review

The review will consider the role and objectives of the facilitated gas markets currently in operation on the east coast and set out a road map for their continued development in order to meet the Council's vision for the market. Opportunities to improve market outcomes including changes to the market structure to enhance liquidity, improve transparency, more effectively manage risk and support the continued integration of the east coast market will be a key focus.

It will be increasingly important given the growing international influence on the Australian gas market that gas supply can reach its highest value end-use, both domestically and for export, and that trading activities can occur across the interconnected markets with low transaction costs and supported by effective risk management processes.

The review will also consider appropriate regulatory arrangements for efficient access to and use of pipeline capacity in order to deliver appropriate incentives and signals to facilitate efficient and timely investment in gas transportation infrastructure and storage. This will include an assessment of the effectiveness of the existing arrangements and, where necessary, options for reform of these arrangements.

The Council expects the AEMC to develop specific actions that can be implemented to strengthen the structure and competiveness of the east coast gas market. Where possible, the AEMC is to consider making recommendations for immediate implementation.

Scope

The AEMC is required to review the development of the facilitated gas markets and gas transmission pipeline capacity arrangements in eastern Australia. In undertaking the review, the AEMC should consider:

1. Facilitated markets: enhancing transparency and price discovery in the wholesale markets, and reducing barriers to entry

Australia has a number of facilitated markets, which include the DWGM, the Short Term Trading Markets (STTMs) and the Wallumbilla Gas Supply Hub. These markets do not seek to replace the trade of wholesale gas through bilateral contracts, but rather provide additional market options which can lead to greater transparency and price discovery.

The gas supply hub is a voluntary market where sellers offer to sell gas and buyers offer to buy gas with the market operator responsible for matching buyers and sellers at the same price. Transportation does not form part of the transaction. In contrast, the STTM is a wholesale gas balancing mechanism established at defined gas hubs. The objective is to facilitate the short term trading of gas between pipelines, participants and production centres. It uses bids, offers and forecasts submitted by participants and pipeline capacities to determine schedules for deliveries from the pipelines which ship gas from producers to transmission users and the hubs.

The STTMs were designed as wholesale markets overlaid on existing contractual arrangements for supplying gas from multiple facilities to a defined hub to better reflect the current value of gas and provide incentives that improve system reliability. Finally, the DWGM is a single integrated market that provides participants with the ability to trade imbalances and purchase wholesale gas. The DWGM framework has provided a reliable and secure system for the trading and transportation of gas in Victoria.

The AEMC is to consider the optimal type and number of facilitated markets on the east coast, taking into account the current arrangements and changing gas market conditions. The AEMC should assess short and longer term options to improve the accuracy and transparency of market information to enhance the wholesale price discovery process and support competition in upstream and downstream markets. The AEMC should also consider opportunities to harmonise the market parameters of the facilitated markets across the east coast, such as prudential obligations, gas day trading times and market price caps. As each facilitated market is operated differently, there may be opportunities to reduce transaction costs for participants operating in, or looking to participate in, multiple trading hubs.

2. Improving effective risk management in Australian gas markets

Across Australia's facilitated markets, there are varied management techniques to mitigate price risks (long term contracts, or limited capacity instruments). However, the Council is concerned that as the markets develop the ability for participants to hedge risk using these techniques is being impacted.

The Council has committed to establishing the necessary enabling conditions for the development of a liquid trading market for the eastern gas market, including through access to transmission pipelines. The AEMC is to provide advice on the adjustments necessary in the markets and regulatory arrangements governing pipeline access to facilitate liquid and competitive wholesale spot and forward markets which also provide tools for participants to price and hedge risk. In particular, the AEMC should investigate the issues associated with, and potential benefits of, the development of an efficient financial derivative market for gas.

3. Signals and incentives for efficient access to and use of pipeline capacity

Pipeline capacity in Australia has grown steadily in recent years providing a greater degree of interconnectedness between gas supply resources and demand centres. The current framework has successfully brought new capacity on line to meet demand and allocated costs to the beneficiaries of the investment. While recognising that the current framework has delivered investment, the Council has committed to examining the access arrangements governing gas pipelines, reducing any barriers to access and facilitating continued pipeline investment, as enabling conditions for more liquid gas markets in both the short and longer term.

The AEMC is to consider whether the provision of accurate and transparent information on pipeline and storage operations, and capacity, is appropriate and whether there are impediments to the efficient use and opportunities for trade in pipeline capacity. This may include more structured or harmonised capacity contracting arrangements.

Further, the Council expects the AEMC to recommend changes to the design of the markets that will, strengthen signals and incentives for efficient investment in, access to, and use of pipeline capacity across eastern Australia.

In making its recommended changes, the AEMC should consider any implications for the existing transmission access and investment framework, including the importance of existing property rights within that investment framework.

Considerations

In undertaking the review and forming its recommendations, the AEMC is to consider the:

- Size, maturity and interconnectedness of the east coast gas market;
- Types and needs of participants including producers, transporters, retailers and end users (large and small manufacturers, small business and households);
- Changes being driven by the establishment of the LNG export industry;
- Physical characteristics of the market as a whole as well as the particular locations serviced by any facilitated market;
- Legal and regulatory arrangements supporting pipeline access;
- Costs and benefits of any recommendations;
- Nature of the commercial arrangements underpinning the supply and transportation of gas; and
- Relevance of international experience to the development of the east coast gas market

The AEMC is also to incorporate the findings and recommendations from its concurrent review of the DWGM.

More broadly, the AEMC is also to consider the:

- National gas objective; and
- COAG Energy Council's Gas Market Vision and Gas Market Development Plan.

Consultation, timeframes and deliverables

The review will be conducted over two phases. The first phase will develop the overall direction for east coast market development to support the Council's vision. Drawing on a fact-base of the current market outcomes the report will provide a gap analysis between the Council's vision and the existing market design including an assessment of whether options currently being discussed and included in the Gas Market Development Plan could address the gap. Recommendations in the Phase 1 report will highlight specific actions for immediate implementation and identify any rule change recommendations for the Council's consideration. The second phase will more fully develop the medium and long term adjustments necessary to implement the Council's vision including the transition path required.

The AEMC will provide the Phase 1 report to the Council in June, 2015 to allow the Council to be considering rule change recommendations from that work while the Phase 2 work is ongoing. This should allow for a faster implementation timeline. A draft Phase 2 report will be provided to the Council ahead of the December meeting. This will give the Council the ability to assess whether further work on the potentially more transformative recommendations is still required as well as speeding up any final decisions from the Council on rule change requests.

Despite an accelerated timeline for this work the AEMC will hold public forums/workshops on both phases of work and invite participants to make written submissions to presentations and working papers distributed in the forums.

A single stakeholder reference group will also be convened to provide input and guidance on this review, as well as the AEMC review of the DWGM. The reference group will meet periodically and the AEMC will use best endeavours to ensure the members include AEMO, AER, pipeline owners, retailers, producers, consumer representatives and any other party the AEMC deems appropriate. The AEMC will also provide regular updates and seek regular feedback from the Gas Market Working Group.

The AEMC is to work closely with AEMO throughout the review to utilise AEMO's expert advice in assessing the operational implications of any recommendations.

Milestone	Due Date
Stage 1: setting the directions for east coast markets	
Public forum (seek written submissions)	February 2015
Draft report for consultation	April 2015
Final report to COAG Energy Council	June 2015
Stage 2: addressing the medium to long term issues	
Directions paper and public forum	August 2015
Draft report for consultation, including request for COAG response on any longer term initiatives	December 2015
Final report to COAG Energy Council	Following COAG Energy Council's response to the draft report

B Assessment Framework

The purpose of this appendix is to outline the assessment framework that the Commission will use for both the East Coast and DWGM reviews. In providing advice to the Energy Council and Victorian Government, we will explain how our recommendations meet the assessment framework.

The assessment framework integrates the factors set out in both terms of reference that the AEMC must have regard to and articulates the relationship between them. High level principles that guide our market development and rule making work are also outlined, along with attributes that we consider are associated with a well-functioning, workably competitive gas market.

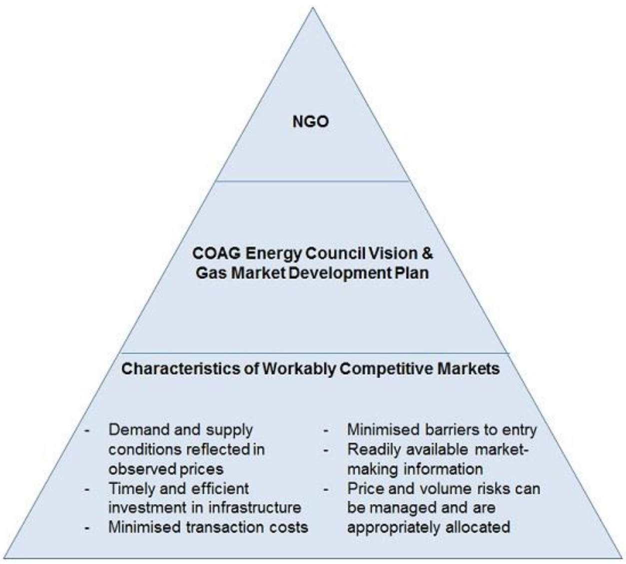
B.1 Assessment framework structure

In accordance with the terms of reference, the assessment framework is structured so that the single overarching objective guiding the AEMC is the National Gas Objective (NGO).

In applying the NGO, the AEMC will have regard to the Energy Council's Vision and Gas Market Development Plan. The Vision is a statement agreed by the Commonwealth, state and territory energy ministers setting out the high level direction that gas market development should take in Australia for the NGO to be achieved. The Gas Market Development Plan is a program of work currently underway that supports the Vision.

Sitting below the NGO and Vision are high level attributes that the Commission considers support the development of well-functioning, workably competitive markets and that are generally required for the NGO and Vision to be achieved. The relationship between the three aspects of the assessment framework is illustrated in Figure B.1, and each is discussed below.

Figure B.1 Assessment framework



B.2 National Gas Objective

In accordance with the two terms of reference, the AEMC must have regard to the NGO in undertaking these reviews. The NGO is set out in section 23 of the National Gas Law and states:

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The NGO is structured to encourage energy market development in a way that supports the:[230]

1. efficient allocation of natural gas and transportation services to market participants who value them the most, typically through price signals that reflect underlying costs;

2. provision of, and investment in, physical gas and transportation services at lowest possible cost through employing the least-cost combination of inputs; and

3. ability of the market to readily adapt to changing supply and demand conditions over the long-term by achieving outcomes 1 and 2 over time.

The three limbs of efficiency described above are generally observable in a well-functioning, workably competitive market and together work to promote the long-term interests of consumers of natural gas.

In accordance with the NGO, the AEMC will take into account the long term interests of all consumers of natural gas throughout this review. The AEMC notes that there are numerous types of consumers of natural gas in the Australian economy, including: residential and commercial users; industrial and manufacturing users; gas fired generators; and LNG producers.

As with all rule changes and reviews, when applying the NGO we will have regard to the following set of high-level principles:

- competition and market signals will generally lead to better outcomes than centralised planning and regulation, as competing energy businesses have an incentive to meet consumers' needs efficiently;

- where it is required, regulation should be targeted, fit-for-purpose, provide incentives that attempt to imitate the outcomes of a workably competitive market, and involve regulatory costs proportionate to the materiality of issue that the regulation seeks to address;

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230 These three outcomes are commonly referred to as allocative, productive and dynamic efficiency, respectively.

- risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them; and
- market and regulatory frameworks should be flexible and provide firms with a clear and consistent set of rules that allow them to independently develop business strategies and adjust to changes in the market. Frameworks should be resilient to changing supply and demand conditions, and patterns of flow, over the long-term.

These principles guide the direction of the recommendations stemming from these reviews towards achieving the NGO.

B.3 Energy Council Vision and Gas Market Development Plan

In accordance with the terms of reference, the AEMC must also have regard to the Energy Council's Vision for Australia's future gas market and Gas Market Development Plan. Specifically, the Energy Council has requested that this review consider the role and objectives of the facilitated gas markets on the east coast, and set out a road map for their continued development in order to meet the Energy Council's Vision for Australia's future gas market, which is as follows:[231]

> "The Council's vision is for the establishment of a liquid wholesale gas market that provides market signals for investment and supply, where responses to those signals are facilitated by a supportive investment and regulatory environment, where trade is focused at a point that best serves the needs of participants, where an efficient reference price is established, and producers, consumers and trading markets are connected to infrastructure that enables participants the opportunity to readily trade between locations and arbitrage trading opportunities."

The Vision is underpinned by four broad policy work streams and related outcomes:[232]

1. **Encouraging competitive supply:**
   - (a) Improvements to the regulatory and investment environment so that gas supply is able to respond flexibly to changes in market conditions.
   - (b) A "social licence" for onshore natural gas development achieved through inclusion, consultation, improving the availability and accessibility of factual information relating to resources projects, and rigorous science to ensure that communities concerns are addressed.
2. **Enhancing transparency and price discovery**:

231 COAG Energy Council, *Australian Gas Market Vision*, December 2014, p. 1.

232 COAG Energy Council, *Australian Gas Market Vision*, December 2014, pp. 2-5. We note that these four work streams are also stated in the *Gas Market Development Plan*, available at: http://www.scer.gov.au/workstreams/energy-market-reform/gas-market-development/

(a) Increased flexibility and opportunity for trade in pipeline capacity.

(b) Competitive retail markets that will provide customers with greater choice and large users with enhanced options for self-supply and shipment.

(c) Provision of accurate and transparent market making information on pipeline and large storage facilities operations and capacity, upstream resources, and the actions of producers, export facilities, large consumers and traders.

3. **Improving risk management:**

(a) Liquid and competitive wholesale spot and forward markets for gas that provide tools for participants to price and hedge risk.

(b) Access to regional demand markets through more harmonised pipeline capacity contracting arrangements which are flexible, comparable, transparent on price, and non-discriminatory in terms of shippers' rights, in order to accommodate evolving market structures.

(c) Harmonised market interfaces that enable participants to readily trade between locations and find opportunities for arbitrage and trade.

(d) Identified development pathways to improve interconnectivity between supply and demand centres, and existing facilitated gas markets, which enable the enhanced trading of gas.

4. **Removing unnecessary regulatory barriers:**

(a) Regulation of gas supply and infrastructure is appropriate and enables participants to pursue investment opportunities, in response to market signals, in an efficient and timely manner.

While stream 1, "encouraging competitive supply," is largely outside the scope of the AEMC's reviews, it provides necessary context to our more thorough consideration of issues relating to streams 2 to 4.

Overall, the Vision provides the Commission with a high level policy statement to guide its analysis through the review. It does this by setting out the broad direction that gas market development should take in order to meet the NGO. The elements that make up the Vision can be considered the "means" of promoting the overarching objective – the NGO – through increasing the efficiency of the gas market, for the long term benefit of consumers of natural gas services.

B.4 Characteristics of a well-functioning gas market

While the NGO serves as the overarching objective and the Vision provides the high level policy direction, the AEMC is also guided by a number of attributes that represent well-functioning, workably competitive markets.[233] These are:[234]

1. Demand and supply conditions reflected in prices: markets participants should have access to a credible reference price reflective of underlying supply and demand conditions that usefully aids commercial decision making.
2. Timely and efficient investment in infrastructure: efficient additions to, and expansions of, infrastructure enable supply to meet demand while minimising the cost of excess capacity.
3. Readily available market information: efficient outcomes are likely to be achieved when participants (current and potential) have access to clear, timely and accurate information about prices and factors driving prices, such as supply and demand conditions.
4. Price and volume risks can be managed and are appropriately allocated: participants being able to manage operational risks to delivery of physical gas while maintaining safe operating parameters, as well as being able to insure themselves adequately against financial risks.
5. Minimised barriers to entry: barriers to entry (and exit) can be a function of market structure, government regulation, industry-specific sunk costs or geography, and certain barriers have the potential to detract from the ability of markets to deliver efficient outcomes.
6. Minimised transaction costs: efficient transaction costs support timely and efficient investments in infrastructure and encourage competition.

These characteristics, if in place, would form a strong foundation for facilitated gas markets and transportation arrangements in eastern and southern Australia to promote the NGO and achieve the Energy Council's Vision.

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233 Application by Chime Communications Pty Ltd (No 2) [2009] ACompT 2, offers a "shorthand" description of workable competition which is "...a market with a sufficient number of firms (at least four or more), where there is no significant concentration, where all firms are constrained by their rivals from exercising any market power, where pricing is flexible, where barriers to entry and expansion are low, where there is no collusion, and where profit rates reflect risk and efficiency."

234 We note that these build on factors previously identified and used by the AEMC and others. See, for example: K Lowe Consulting, *Gas Market Scoping Study*, A report for the AEMC, July 2013, p. 86; and: ESAA, *Assessment of the East Coast gas market and opportunities for long-term strategic reform*, Final Report, May 2013, p. 37.

C Review process

C.1 Review process

The East Coast Review has been structured over two stages. In July 2015, the Commission published the Stage 1 Final Report, which included a gap analysis between the current market arrangements and the Energy Council's Vision, as well as recommendations that could be progressed in the short term. Appendix D provides details of the current progress of the implementation of the Stage 1 recommendations.

In this Stage 2 Final Report, the Commission has recommended a gas market development roadmap that brings together recommendations on wholesale gas and pipeline capacity trading and information provision. Stage 2 of the review more fully developed medium and long-term adjustments required to achieve the Energy Council's Vision, including the transition path.

The Commission has undertaken a consultative approach in conducting both the East Coast and DWGM reviews, as summarised in the table below.

Table C.1 Review process

Date	Milestone	
	East Coast Review	**DWGM Review**
20 February 2015	Terms of Reference	
25 February 2015	Public Forum and Discussion Paper	
4 March 2015		Terms of Reference
7 May 2015	Stage 1 Draft Report	
23 July 2015	Stage 1 Final Report	
6 August 2015	Wholesale Gas Markets Discussion Paper	
10 September 2015		DWGM Discussion Paper
18 September 2015	Pipeline Regulation and Capacity Trading Discussion Paper and Information Provision Working Group Discussion Papers	
30 September 2015	Public Forum	
4 December 2015	**Stage 2 Draft Report**	DWGM Draft Report
3 March 2016	Pipeline Access Discussion Paper	DWGM Supplementary Discussion Paper
May 2016	Stage 2 Final Report	
September/October 2016		DWGM Final Report

In addition to the documents and forums listed above, a working group was established to consider issues related to information provision, which met on four occasions between August and October 2015 and was supported by a number of working papers to develop the issues and proposed solutions.

The Commission appreciates the time and effort required to prepare submissions and attend meetings, particularly over such condensed timeframes, and thanks stakeholders for engaging with the Commission throughout the review process.

C.2 Advisory group

As required by the terms of reference, the Commission established an Advisory Group that operated across the East Coast and DWGM reviews. This group was used to provide strategic advice and expertise to the Commission over the course of the review. It met periodically and was chaired by John Pierce, AEMC Chairman. Advisory Group member organisations are listed in Table A.1.

The Commission gratefully acknowledges the ongoing contribution made by the members of the Advisory Group.

Table C.2 Advisory Group Members

Member	Role
Australian Energy Market Operator	Market operator
APA	Pipeline owner
Jemena	Pipeline owner and distributer
Australian Pipeline and Gas Association	Pipeline association
Santos	Producer
ExxonMobil	Producer
Origin Energy	Producer, retailer and gas fired power generator
AGL Energy	Producer, retailer and gas fired power generator
Energy Australia	Retailer and gas fired power generator
Simply Energy (GDF Suez Australian Energy)	Retailer (small)
QGC	LNG exporter
APLNG	LNG exporter
Visy Australia	Customer (large)
Energy Users Association of Australia	Customer representative (large)
St Vincent de Paul	Customer representative (small)

D Implementation of Stage 1 recommendations

In the Stage 1 Final Report, the Commission recommended four measures that could be progressed in the short-term to address a number of immediate issues identified in the first stage of the review. The following provides a brief update on the current status of these initiatives.

D.1 Introduction of a wholesale gas price index

The Commission recommended that greater transparency on wholesale gas prices would be useful as a transitional measure until there is an efficient reference price available for market participants and other interested parties. Our preferred approach was to work with the Australian Bureau of Statistics (ABS) to develop a survey-based gas price index that would measure the trends in prices payable under bilateral contracts over time.

The index would be compiled as an extension of the existing Producer Price Index by surveying large gas users that purchase gas directly from producers, including industrial users, gas-fired generators, retailers and LNG producers. While it would not reveal absolute price levels, the index would provide greater transparency around the direction and magnitude of changes in the price of confidential GSAs.

To progress this recommendation, the Commission has led a process to engage with the ABS and industry. Stakeholder workshops were held in Sydney and Perth on 18 August and 14 September, respectively. In total, around 70 stakeholders registered to attend from industry, governments and energy market institutions. The purpose of the workshops was to facilitate a discussion between ABS staff and industry around methodology, data collection, confidentiality arrangements and other issues associated with compiling the index.

Following this round of consultation, the ABS developed a proposal for a new output producer price index (PPI) for natural gas extraction.[235] Stakeholders were invited to provide further feedback on the proposal. An overview of submissions was then provided by the ABS at an additional workshop co-chaired by the AEMC and ABS in Sydney on 17 February 2016. The ABS intends to publish an information paper in late-June 2016 to provide a formal response to the submissions received, as well as some further methodological information about the index design.

The ABS started development of the natural gas extraction PPI in March 2016. Face-to-face meetings were held with east and west coast gas producers throughout April and in early May 2016 with the aim of enrolling producers in the ABS sample, to obtain historical data for a time series, and to develop price specifications for quarterly

235 This proposal was published in Information Paper: Developments in Producer Price Indexes for Natural Gas, Dec 2015 (Cat No. 6427.0.55.008). This paper also provides an overview on already published price indexes related to the gas industry.

data collection. The ABS has also begun work on developing index structures, although this is contingent on finalising sample and price specifications.

The ABS will commence collection of price data from sampled gas producers from June quarter 2016, and no later than September quarter 2016. The initial data collection will include back data that enables the ABS to build an historical time series and get an immediate sense of the robustness of the natural gas extraction PPI.

Provided there are no significant statistical issues with the data, the intention is to publish the natural gas extraction PPI as part of Producer Price Indexes, Australia (Cat No. 6427.0) for December 2016 quarter (released January 2017), and no later than March 2017 quarter (released April 2017). The publication of the new index will be publicised in the previous quarter publication.[236] The first quarter of publication will be accompanied by a brief feature article highlighting the index.

D.2 Rule change to harmonise the gas day

Trading of gas is conducted over "gas days", and the timing of these currently differs across the east coast.[237] The Commission recommended that the Energy Council submit a rule change to the AEMC to introduce a consistent gas day start time. Harmonising the timing of gas days may remove some of the complexity for parties that operate across multiple markets and assist the process of increasing interoperability across markets.

The Energy Council agreed at its July 2015 meeting to submit the rule change, and it has since been developed by Council officials. The gas day harmonisation rule change request was submitted on 26 November 2015. The AEMC initiated the rule change process on 3 March 2016.

D.3 NGL amendments to allow any party to propose a DWGM rule change

The NGL currently provides that applications for rules regulating the DWGM can only be made by AEMO or the Minister of an adoptive jurisdiction.[238] The Commission recommended that this restriction be removed, on the basis that it may represent a barrier for some market participants to influence market development and is inconsistent with the governance applying to other gas and electricity markets.

The Council also agreed to this measure at its July 2015 meeting. We understand that officials are progressing the amendment as a component of a number of legislative packages scheduled for 2016.

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236 Note these timeframes are indicative. There are many dependencies within a price index development that can impact on delivery. The ABS will not publish an index until it is satisfied with the statistical quality, and this is subject to an internal approvals process.

237 Gas days start at 6:00am in Victoria, 6:30am at the Sydney and Adelaide STTM hubs, and 8:00am at the Brisbane STTM hub and Wallumbilla gas supply hub.

238 Victoria is currently the only adoptive jurisdiction.

D.4 Enhanced Information for Gas Transmission Pipeline Capacity Trading rule change

On 16 July 2015, the AEMC commenced consultation on a rule change received from the Energy Council to provide enhanced gas transmission pipeline capacity trading information on the Bulletin Board. In the Stage 1 Final Report, the Commission noted that it would consider whether there were any other informational gaps that fell within the scope of the rule change. The report raised the possibility of considering suggestions made by stakeholders for additional information on storage facilities and volumes, and data on linepack, as well as potential improvements to medium-term capacity outlook information.

On 17 December 2017, the Commission made a final determination[239] which requires the following additional information to be reported by gas market participants:

- Transmission pipeline operators - 12 month uncontracted capacity outlook, the names of contracted shippers, data from their capacity trading platforms, additional gas flow data and more detailed facility data.

- Production facility operators - more detailed information on network connection points.

- Storage facility operators - the actual volume of gas held in the facility; aggregated injections and withdrawals for the previous gas day, nominated for each gas day and a seven-day forecast; and a 12 month outlook of uncontracted storage capacity. Storage facilities that are used solely as part of production facilities will be required to provide the same information as non-exempt facilities other than aggregated injection and withdrawal nominations for each gas day, and a seven day forecast.

- All facility operators - medium term capacity outlooks using a new standard format.

The rule is likely to contribute to better informed decision making by stakeholders and lower transaction costs. These are likely to result in more efficient investment in and use of gas services, which would have long term benefits for consumers. Consumers are also expected to benefit from greater competition in the use and provision of gas services. The new rule comes into effect from 6 October 2016.

239 AEMC, *Enhanced Information for Gas Transmission Pipeline Capacity Trading*, Rule Determination, 17 December 2015, Sydney.

E Wholesale gas market and pipeline framework design options

Gas trading markets operate at hubs, which are defined locations on a pipeline system where the transfer of ownership and pricing of gas takes place. Much of the Commission's work over Stage 2 of the review has been to identify and assess different approaches to wholesale gas market and pipeline framework design that aim to support the development of liquid trading in gas. In particular, we have considered two models that have been successfully applied in overseas markets:

- gas commodity trading hubs located at specific physical points, supported by arrangements which allow for gas to be readily transported between these points by also trading pipeline capacity; and
- "virtual" trading hubs where market participants can obtain access to the totality of a given pipeline system covered by the hub and trade gas with any other participant flowing gas elsewhere on the system.

This appendix provides an explanation and assessment of these two approaches. It is structured as follows:

- Section E.1: Physical hubs supported by pipeline capacity trading;
- Section E.2: Virtual hubs;
- Section E.3: Trade-offs between physical and virtual hubs; and
- Section E.4: Applicability of physical and virtual hubs in Eastern Australia.

E.1 Physical hubs supported by pipeline capacity trading

A physical hub is a specific geographical point in the gas pipeline network where gas delivered to and transferred from that location is priced and traded.[240]

In order to trade gas at a physical hub, shippers must physically transport gas to and from the location. Shippers therefore require transportation rights from points of production, between hubs, and to demand points. These rights can be bestowed to shippers through contracts with pipeline owners, as in the Australian system of contract carriage (through GTAs). However, the efficiency of the gas commodity trading at the hub will depend on the extent to which capacity rights are available (or can be reallocated) to market participants wishing to trade.

Physical hubs provide signals on the price of gas at specific locations on the system, while the price difference between two hub locations can provide signals for investment in pipeline capacity. The STTM hubs in Adelaide, Brisbane and Sydney and the GSH at Wallumbilla can be broadly characterised as physical hubs.

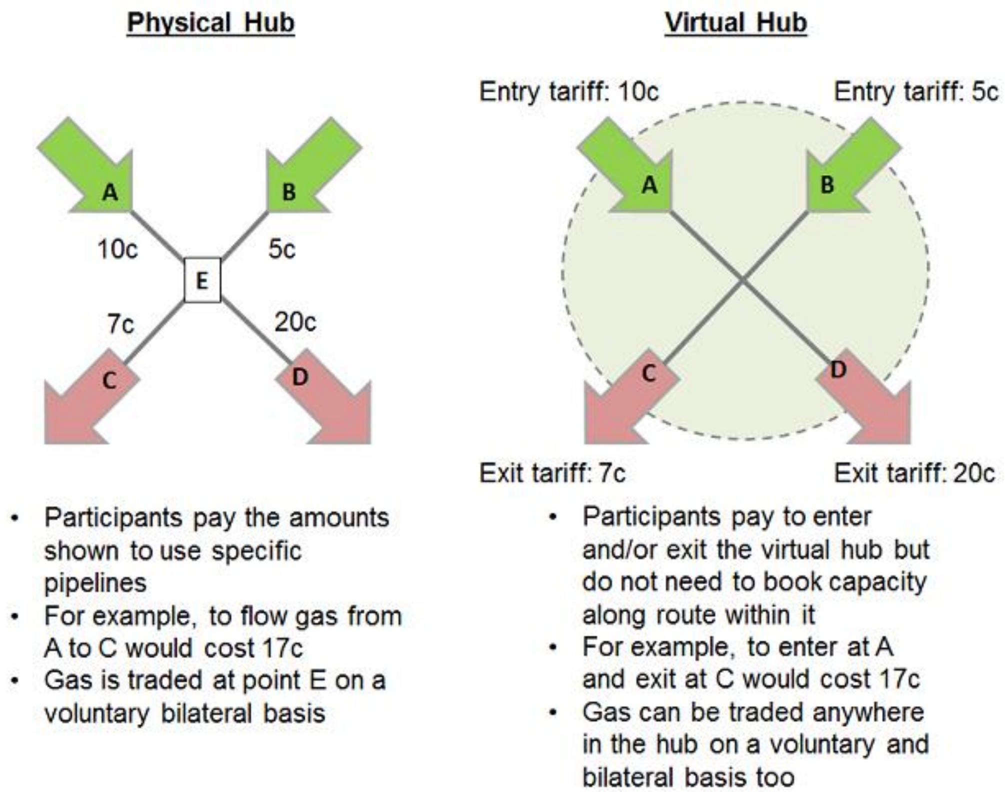
240 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 33.

E.2 Virtual hubs

In contrast to a physical hub, a virtual hub pools trading at a notional point that extends across all, or part of, a pipeline system. Virtual hubs allow for title transfer of gas anywhere within the definition of the hub, with a single price for all trades of gas within the area regardless of the particular location within the hub, obviating the need to purchase point to point pipeline capacity.[241]

Within a virtual hub, a hub operator manages flows within and between the pipelines forming the network. The hub operator's management of flows between pipelines or different parts of the network within the hub is automatically provided so, unlike under contract carriage, market participants are not required to contract transportation capacity *within* the hub.[242,243] Instead, participants simply ship gas to one of the entry points and withdraw gas from any of the exit points on the system.

Figure E.1 Physical and virtual hubs



Source: AEMC derived from: FTI, *East Coast and DWGM Gas Reviews*, Presentation to Public Forum, 30 September 2015, available at: http://www.aemc.gov.au/getattachment/2ada4f65-b34e-486d-8055-3148e6245d14/Public-Forum-Slides.aspx

241 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 45.

242 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 46.

243 The arrangements applying to the DTS in Victoria have come to be known as a "market carriage" system, as access to pipeline capacity is primarily determined by outcomes in the Declared Wholesale Gas Market. However, in international terms, market carriage is an unusual form of virtual hub.

Figure E.1, above, explains the concept of virtual hubs, by showing a physical hub on the left and a virtual hub on the right. Participants at the physical hub pay to use specific pipelines to transport gas to hub E where it is traded. At the virtual hub, participants pay to enter or exit the virtual hub but do not need to book capacity along the pipeline route. Gas is traded notionally anywhere within the virtual point, not at a specific location such as point E in the physical hub. This notional trading supports the concentration of liquidity as buyers and sellers are pooled across the hub and can trade gas irrespective of where it actually is in the physical system.

Where there is no discriminatory access to pipeline capacity and capacity rights can be readily defined and easily tradeable, trading at physical and virtual hubs is similar. This is shown in Figure E.1, where the cost of shipping gas between any of the points is the same for both hub designs.

E.3 Trade-offs between physical and virtual hubs

These two approaches to hub design set out above each come with their own advantages and disadvantages, with the result that their appropriateness can vary according to the relevant circumstances.

E.3.1 Assessment of physical hubs

Physical hubs for the trading of gas can develop in response to market demand for them, and require less regulatory intervention and oversight to establish and operate as compared to virtual hubs. Combined with effective pipeline access arrangements, the market-led price discovery process at the specific hub locations can provide signals for:

- efficient *provision of, and investment in* pipelines between locations; and
- efficient *allocation* of transport services and natural gas where it is most valued.[244]

However, for these benefits to emerge, the price discovery process at the physical hub need to be reliable, which in turn requires liquidity in the market at the hub. There are a number of prerequisite circumstances for liquidity to emerge:

- physical hubs require a large number of market participants being able to trade at the specific hub locations;[245] and
- market participants require flexible, low cost and non-discriminatory access to pipeline capacity to get to and from hubs, and providing this can require

244 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 40-41.

245 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 41-43.

sufficient competition in primary and secondary markets for pipeline capacity to exist. Without this access, the ability to trade at the physical hubs is reduced.[246]

Consequently, a certain level of regulatory intervention and supervision may be necessary to stimulate the development by industry of effective arrangements for pipeline access (that is, to improve the ability and incentive of shippers and pipeline owners to allocate capacity to the party that values it the highest). However, even with these initiatives, in highly meshed networks it may be challenging to facilitate efficient trading of capacity between shippers. Under such circumstances, the cost and complexity of a market-driven approach to appropriately allocate and reallocate capacity rights between shippers may be prohibitively high.

E.3.2 Assessment of virtual hubs

Virtual hubs have benefits in circumstances when physical hubs have drawbacks:[247]

- virtual hubs facilitate trading by allowing market participants to trade anywhere within the hub without having to book pipeline capacity to transport the gas between particular points. This reduces transaction costs and is a particular advantage on networks where there may be several nodes at which capacity bookings may otherwise be required;
- by virtue of a larger footprint, virtual hubs pool a larger number of market participants, enhancing liquidity; and
- problems of inflexible, high cost or discriminatory access to pipeline capacity are addressed *within* a virtual hub because access to the notional trading point is automatically provided to market participants, further enhancing liquidity once their gas is inside the hub. Virtual hubs are therefore particularly useful where networks are highly meshed, or where pipeline access is otherwise problematic. Nevertheless, market participants still need adequate access to, from and between virtual hubs.

By promoting liquidity, virtual hubs serve to promote competition in the wholesale gas market and, by improving the reliability of price signals, promote the efficient allocation of gas where it is most valued.

However, the main drawbacks of a virtual hub compared to a physical hub are that, because of the lack of locational signals:

- there is a need to manage gas flows *within* the hub, which can result in higher costs that may largely have to be smeared across hub users or in the amount of long-term capacity rights being reduced;[248]

246 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 40.

247 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 54.

248 For a more detailed explanation, see FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 57-58.

- investment signals will be weaker and less precise than under contract carriage. Although investment signals can be given at entry and exit points into and out of the system, decisions to invest to reinforce specific flow paths *within* the hub will be made by the pipeline owner in response to the signals given by the purchase of entry and exit capacity.[249]

Furthermore, virtual hubs require a greater degree of regulatory intervention to establish and operate, for example in defining the hub's size and location and setting tariffs for pipeline access.[250] While the economic regulation of capacity within virtual hubs can ameliorate any market power concerns around the accessing pipeline capacity on a non-discriminatory basis, the usual result is that it effectively "entrenches" the monopoly provision of pipeline capacity by the incumbent pipeline owner - to try to facilitate competition in capacity expansions can further increase the level of regulatory complexity.

Overall therefore, the approach to designing virtual hubs is one of trading off the benefits of a greater geographical footprint to have higher liquidity within the hub with that of the increased risk of congestion and weakened locational signals within the hub. It is important to emphasize, however, that the optimal amount of congestion within a virtual hub is unlikely to be zero – the benefits to customers of greater liquidity may mean that some congestion on some occasions is a price worth paying.

Table E.1 Comparison of physical and virtual hubs

Physical hubs		Virtual hubs	
Pros	**Cons**	**Pros**	**Cons**
Trading locations determined by market demand	Dependent on a large numbers of market participants being able to trade at each specific hub	Flexibility to trade anywhere on a pipeline system without having to book point-to-point capacity	Requires management of flows within hub which can lead to increase in (smeared) costs and/or reductions in capacity
Locational prices provide strong signals for pipeline investment, which is driven by private entities	Competition in primary and secondary markets for pipeline capacity and hub services important to allow ready access to hubs	Liquidity is enhanced through pooling a larger number of buyers and sellers	Although investment signals given at entry/exit points, limited locational investment signals within hub
Lower level of regulatory oversight	Facilitating pipeline capacity trading particularly challenging when network is complex	Promote efficient use of pipeline system as capacity more easily resold	Regulatory complexity, usually including ex ante incentive regime/economic regulation

Source: AEMC analysis based on FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015.

249 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 56.

250 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 57-58.

Conversely, where physical hubs exist, locational signals at specific network locations will be strong provided there is a sufficiently robust reference price. This can be negatively impacted if trades are spread across multiple physical hubs in a concentrated market, or if the ability to source pipeline capacity to ship gas to and from hub locations is affected by high transaction costs or limited competition for pipeline services. These key trade-offs between physical and virtual hubs are set out in Table E.1 above.

E.3.3 Experience in overseas markets

As can be seen from the discussion above, whether to opt for an approach based around physical hubs or virtual hubs depends on the circumstances of the broader market environment. This can be illustrated by the differing experiences in the United States (US) and European Union (EU).

The US has approximately 200 physical hubs, connected by an extensive network of pipelines.[251] This use of an approach based around physical hubs is in keeping with the circumstances found in the US:

- there is a large number of market participants and pipeline owners, facilitating liquidity at the physical hubs and assisting with the development of trading in pipeline capacity to support the commodity trading;[252] and
- the network topology is primarily defined by long, point-to-point pipelines[253], meaning there is relatively low complexity in gaining access to hubs via the bilateral contracting of pipeline capacity (further facilitated by regulations aimed to improve pipeline access). In such circumstances, the less precise investment signals and lack of competition in the provision of pipeline capacity under virtual hubs could result in significant costs.

In contrast, the EU has developed a system where each member state has one (or occasionally more) virtual hub(s) superimposed on top of its pipeline system. Again, this approach aligns with local circumstances, where there are:

- relatively fewer market participants and pipeline owners (as market structures have typically evolved from a single monopoly provider in each member state), meaning that virtual hubs serve to pool all potential competitors in a given region, maximising liquidity; and
- often relatively small, highly meshed transmission networks, meaning that gaining access to a specific point of the network might otherwise be complex and costly without a virtual hub.[254] The associated drawbacks of less precise locational investment signals and a lack of competition in the provision of

251 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 33.

252 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, pp. 42-43.

253 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 42.

254 FTI, *Conceptual design for a virtual gas hub(s) for the east coast of Australia*, November 2015, p. 45.

pipeline capacity are less costly in European markets than they would be over a more geographically dispersed area.

E.3.4 Conceptual framework

The assessment of the differing approaches to hub design, combined with our observations of practical experience in overseas markets, suggests that physical hubs:

- can generate sufficient liquidity in trading if point-to-point capacity rights are easily defined and readily available/tradeable; and
- are better at providing precise investment signals and capturing the potential benefits resulting from the competitive provision of pipeline capacity.

In contrast, the benefits of facilitating a liquid wholesale gas market through virtual hubs are likely to be greater than the associated costs when:

- the current and likely future number of market participants is relatively low, such that liquidity in trading gas is unlikely to develop at physical hubs and a competitive market in pipeline capacity does not emerge to support this; and/or
- the technical characteristics of the pipeline system may mean that frictionless capacity trading and hub services arrangements cannot be practically achieved. In a meshed network with many potential combinations of entry and exit points, it may be more efficient for a hub operator to manage flows and balance the system on behalf of participants.

However, these considerations are unlikely to be black and white – they will require trade-offs and judgements to be made.

E.4 Applicability of physical and virtual hubs in Eastern Australia

Some parallels can be drawn between the broader market environment in Eastern Australia and the markets discussed in the previous section. However, the east coast market arguably suffers from the challenges arising in both the US and Europe.

Like the US, the transmission network is primarily made up of long, point-to-point pipelines, typically between production centres and far distant demand centres. Consequently, the efficiency of investment is a key concern. However, like many markets in the EU, there are a relatively low number of market participants (although lower barriers may stimulate additional competition). As a result, the ability of virtual hubs to pool liquidity may be of significant benefit.

This means that there is not an obvious international precedent to draw on, and that an approach that draws on both models should also be considered.[255]

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255 To a certain extent, this hybrid approach is also observed in the EU. Although the EU gas market primarily consists of a system of regulated virtual hubs, some merchant pipelines not subject to

Box E.1 The Wholesale Gas Markets Discussion Paper

On 6 August 2015, the Commission published the Wholesale Gas Markets Discussion Paper to progress the debate on the future development of wholesale gas trading markets on the east coast of Australia.[256] Three high level market design concepts, ranging from multiple physical hubs to two large virtual hubs, were developed as a way of seeking targeted feedback from stakeholders:

- **Concept 1** - Multiple physical hub locations at major pipeline junctions and production centres across the east coast, with simplified balancing mechanisms in the major capital cities.
- **Concept 2** - A new virtual hub in the north covering the Roma to Brisbane Pipeline and current Wallumbilla GSH (the 'Northern Hub') and a virtual hub in the south covering the Victorian Declared Transmission System (the 'Southern Hub'), with balancing mechanisms at Adelaide and Sydney. Shippers would have to bilaterally contract with pipelines to move gas between these hubs.
- **Concept 3** - One large virtual hub in the north (ie the pipeline system to the north-west of Moomba) and another in the south that, together, cover the entire east coast.

The Commission received 17 public submissions to the discussion paper, which are published on the AEMC website. Through submissions, stakeholders drew out the trade-offs between the concepts, such as Concept 1 being most likely to promote efficient investment while Concept 3 would be most likely to promote liquid trading. A key theme from submissions was that wholesale market design decisions and pipeline capacity trading arrangements are interlinked and cannot be thought of separately.

One example of such a hybrid approach was presented in the Wholesale Gas Markets Discussion Paper as Concept 2, and reflected a view that there may be some advantages in the broader application of virtual hubs on the east coast outside of Victoria. The rationale for selecting the Roma to Brisbane Pipeline (RBP) to be used as the basis for a virtual hub in the north provides a good illustration of the criteria that should be considered in determining whether or not a virtual hub is appropriate:

- A relatively **large number of diverse market participants** (or potential participants) are connected to the RBP. There are significant conventional and unconventional production sources, some large industrial users in Brisbane, retailers servicing distribution-connected users in Brisbane, a number of gas-fired

economic regulation link the hubs. One such example, Interconnector UK, was discussed in Pipeline Regulation and Capacity Trading Discussion Paper, see: AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Pipeline Regulation and Capacity Trading Discussion Paper, 18 September 2015, Appendix B.

256 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, Wholesale Gas Markets Discussion Paper, 6 August 2015.

generators and numerous interconnections to pipelines flowing to the LNG export facilities. There would therefore be substantial benefits from pooling the trading activities of all these parties at one virtual hub, not just due to their absolute numbers but also because their differing demand and production profiles would be complementary and likely to result in trading opportunities.

- The RBP represents a **technically complex system**, with multiple injection and withdrawal points.[257] This means that trading pipeline capacity might be particularly difficult. There would likely be significant benefits of establishing arrangements where shippers were contractually able to flow gas to any other point on the pipeline by procuring a single entry or exit right.

- The footprint of the pipeline system **covers a relatively small area**.[258] Therefore the limited nature of the investment signals given by the sales of entry and exit rights into and out of a virtual hub are less of an issue than for larger systems where any costs associated with inefficient investment could be much greater.

- Finally, the **costs of regulation are relatively low**, as compared to the counter-factual of the status quo. The RBP is already subject to economic regulation through the coverage regime, with the rationale for this arguably reflecting a low likelihood that a competing pipeline will be developed. While the regulatory arrangements applying under a virtual hub would likely be more complex than the current coverage regime, the incremental costs would be lower than for an uncovered pipeline. Equally, the possible effect of entrenching the monopoly status of the pipeline provider can be considered less costly if competitive entry is unlikely in any event.

In circumstances where the above criteria are relevant, the Commission considers that the application of virtual hubs may represent an appropriate long-term model.

Although the establishment a virtual hub would be likely to present complex transitional issues and come with material implementation costs,[259] the Commission is of the view that the development of arrangements for a virtual trading hub model in the Australian context would represent an important part of the regulatory "tool-kit" to support the future development of the market. In particular, if more incremental reforms are unsuccessful in generating a liquid northern trading hub, the Commission considers that it may then be appropriate to introduce a virtual hub in south-east and/or south-west Queensland.

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257 We understand that there are approximately 25 injection and withdrawal points.

258 The mainline of the RBP is 438km long. For comparison, the Moomba to Sydney Pipeline is 2,029km long. Information sourced from AEMC Gas Scheme Register, see www.aemc.gov.au.

259 Given the nature of the current arrangements, establishing a virtual trading hub supported by entry/exit capacity arrangements is likely to be less difficult on the Victorian DTS as compared to pipelines currently operating under contract carriage.

F Monitoring growth in trading liquidity

An important element in determining whether the Energy Council's Vision is being achieved will be monitoring the development of liquidity in the wholesale gas market. Monitoring gas market liquidity on an ongoing basis will allow policy makers, current and potential future industry participants, and the energy market institutions to understand how the gas and pipeline capacity trading markets are performing and the value they provide to gas market participants.

Accordingly, the Commission recommends the Energy Council task it with reporting to Energy Ministers on a biennial basis on the growth in trading liquidity in the Australian wholesale gas and pipeline capacity trading markets. The Commission recommends the first report be provided to the Energy Council by mid-2018.

The scope of the report should include monitoring developments in the Australian wholesale gas market and pipeline capacity trading markets. Initially, as market reforms are implemented, the report should have a particular focus on developments in the east coast gas market.

F.1 Measuring wholesale gas market liquidity

The east coast gas market has six trading hubs and three different wholesale gas trading market designs - the DWGM (Victoria), STTM (Adelaide, Brisbane and Sydney) and GSH (Wallumbilla and Moomba). Since these markets have been implemented, there has been little ongoing analysis on how they are performing, whether they are meeting their intended objectives and how they could be improved to better meet market participants' needs. Ongoing monitoring of liquidity will provide a mechanism for this to take place.

Further, in this report the Commission has made recommendations with a view to achieving the Energy Council's Vision of a liquid wholesale gas market. There are a number of interdependencies in implementing the package of reforms and, while many recommendations should be implemented as soon as possible, others will need to be implemented in sequence. Therefore, as the Commission's recommendations are implemented it is appropriate to monitor how liquidity is growing in the wholesale gas market and the response of participants to the market development process.

Liquidity is commonly defined based on four characteristics:[260]

- **Market depth**: where no single buy or sell order is likely to move the market price excessively.
- **Market breadth**: where a large number of bids to purchase gas and offers to sell gas are present in the market.

260 IEA 2008, Development of competitive gas trading in continental Europe – How to achieve workable competition in European gas markets?, IEA Information Paper, May, p. 46.

- **Immediacy**: the ability to trade large volumes in a short period of time.
- **Resilience**: the ability of the market to recover towards its natural equilibrium after being exposed to a shock.

Broadly speaking, a liquid market is one in which market participants have access to a range of products and can reliably make transactions in a timely way, at a cost-reflective price. We note that liquidity is a broader concept than gas volumes, as adding to the supply of gas may not necessarily result in more gas being traded between different parties.

Liquidity is a multi-faceted concept that involves understanding the number of participants, how they use gas, the peakiness or otherwise of loads, procurement strategies, as well as the total volume of gas consumed. Therefore, in order to evaluate market liquidity a range of indicators, both quantitative and qualitative, need to be considered. Qualitative data collected through surveys of participants are useful because many elements of liquidity, such as aspects related to reputation, trust and culture, cannot be accurately quantified using traditional metrics.

Further, as the eastern Australian gas market is undergoing a transition, the relative importance of liquidity indicators may change over time. Any monitoring of market liquidity that takes place should therefore have the ability to incorporate new metrics into the analysis.

Where threshold values for liquidity metrics are specified, the intention is to use these as guides that represent the characteristics of a liquid market. It is therefore not expected that the market monitoring exercise would see each of these thresholds reached or exceeded or that the thresholds would be used mechanistically to trigger more reform. Insights can, however, be gained by evaluating the liquidity metrics relative to the threshold level and examining the trend in these metrics over time. This, combined with analysis of survey-based qualitative indicators, provides for a holistic assessment of gas market liquidity.

F.2 Stakeholder submissions to Stage 2 Draft Report

Four liquidity metrics were proposed in the Stage Two Draft Report, with an associated threshold value.[261] These metrics are:

1. **Level of participation:** measured by the ratio of market players actively trading at the hubs to physical players on the east coast.
2. **Price relevance:** number of trades required, per product at each hub on a given day to provide confidence that the price signal is meaningful.
3. **Liquidity threshold:** the amount of gas that is simultaneously being offered and requested for each product at a hub so that the product is considered "liquid".

4. **Liquidity trading horizon:** provides an indication as to which products it is possible to trade into the future.

These proposed metrics were supported by a number of parties, including the APGA[262], the EUAA and RWE. RWE noted that monitoring progress towards greater gas market liquidity, and acting quickly and transparently to overcome any impediments, is important.[263] The EUAA suggested that it might be difficult to translate measures of liquidity in Europe and America to an Australian context, but considered the proposed metrics a reasonable starting point.[264]

Jemena and Santos considered that further consultation is needed on the liquidity metrics. Santos questioned whether the metrics would sufficiently address the quantitative intent of the Vision and suggested that it would also be useful to consider the rate of change of the metrics.[265] Jemena expressed concern about the threshold value for the level of participation, as it may not be reasonable to expect that all participants would be interested in trading markets.[266]

Alternative or additional liquidity metrics were suggested by the EUAA, PIAC and AEC, including a metric relating to the size of individual offers,[267] a customer-focused metric,[268] and an assessment of whether market participants are unreasonably reserving capacity.[269]

The threshold values proposed in the Stage 2 Draft Report were the subject of comment in submissions. Stanwell's submission expressed concern that the measures are overly ambitious and that, even if set at a more realistic level, the liquidity measures should not be used as a mechanistic trigger to pre-determined further regulatory reform.[270] The AEC also submitted that the measures proposed appear overly-ambitious, particularly when compared to the liquidity that currently exists in the forward electricity market.[271] AGL suggested that many established markets would not meet the proposed criteria and that it is unrealistic to expect a nascent market to satisfy the proposed liquidity measures.[272]

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261 AEMC *East Coast Wholesale Gas Markets and Pipelines Frameworks Review,* Stage 2 Draft Report, December 2015, pp. 96-98.

262 APGA, submission to the Stage 2 Draft Report, p16

263 RWE, submission to the Stage 2 Draft Report, p3

264 EUAA, submission to the Stage 2 Draft Report, p11

265 Santos, submission to the Stage 2 Draft Report, p. 4.

266 Jemena, submission to the Stage 2 Draft Report, p. 27.

267 EUAA, submission to the Stage 2 Draft Report, p. 11.

268 PIAC, submission to the Stage 2 Draft Report, p. 6.

269 AEC, submission to the Stage 2 Draft Report, p. 2.

270 Stanwell, submission to the Stage 2 Draft Report, p. 6.

271 AEC, submission to the Stage 2 Draft Report, p. 2

272 AGL, submission to the Stage 2 Draft Report, p. 4.

As noted above, the intent of the liquidity thresholds set out in the draft report was to provide a benchmark against which to assess the trend of the liquidity indicators over time. The Commission did not suggest that it was realistic for the east coast market to achieve these indicators in the near term or for further reform to be triggered if the thresholds were not met.

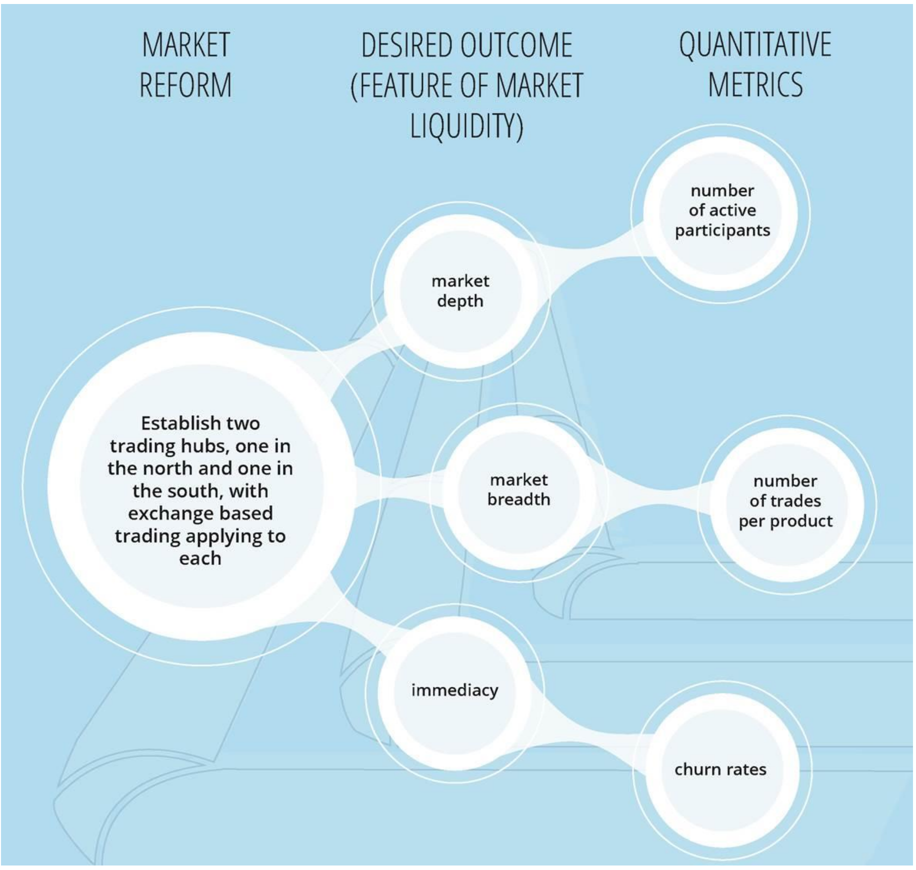
F.3 Liquidity metrics

In order to effectively monitor trading liquidity it is necessary to put in place a framework that is cognisant of the Energy Council's Vision and which identifies outcomes that are consistent with the achievement of this Vision. In other words, a process for monitoring liquidity should be based on identifying characteristics of a liquid gas market and evaluating the state of the market at a given time against these characteristics.

Some aspects of liquidity lead to outcomes that are quantifiable and which can be objectively measured through the use of appropriate metrics. Threshold values for metrics are specified in some cases, these thresholds are set at a level that would be observed in a liquid market. The use of quantitative metrics, in conjunction with the threshold values, allows for an evaluation of whether liquidity exists to be made.

The process for objectively monitoring market liquidity is illustrated in Figure F.1 below.

Figure F.1 Process for monitoring liquidity



The diagram illustrates the process for choosing appropriate metrics to measure market liquidity. Firstly, the desired outcomes of the market reforms are identified. These are informed by the Energy Council's Vision and the characteristics of a liquid market, as discussed above. For each of these characteristics, metrics are chosen that can accurately measure whether they are present in the wholesale gas and pipeline capacity trading markets. For example, the number of active participants is an objective measure of market depth. In a liquid market one buyer or seller cannot move the market price to a great degree; therefore, the more participants there are trading on the market the more likely it is that the market is deep.[273]

The table below provides an overview of the metrics we recommend should be included in the analysis of liquidity in the wholesale gas market. The table includes both quantitative and qualitative metrics and provides information on how the metric will be constructed and the expected trend in these metrics over time. Where appropriate, indicative threshold values are also provided.

Table F.1 Metrics to monitor liquidity in the wholesale gas market

Metric	Description	Trend and/or threshold
Churn rate	Ratio of all traded volumes to demand for the underlying physical product	Around 10 in a liquid market but likely to be much lower as market develops. Trend should be increasing
Bid-offer spreads	The difference between prices on the bid and offer side of the market	Should be narrowing
Number of active participants	The number of participants that have actively traded on the hubs	Increasing toward aspirational ratio of 100 per cent of active market participants to physical players
Number of trades per product	The number of traded transactions per product	Increasing
Range of products traded	Types of products available to trade (including OTC and exchange traded)	Increasing
Confidence of market participants	Survey-based measure of market participants' confidence in the trading hub	Participants should have increasing confidence and be more willing to engage in hub-based trading
Market participants perception of future market developments	Survey-based measure of market participants' perception of future market developments	Participants should expect more hub-based trading to occur

273 It should be noted that resilience is not included in the above diagram. All metrics can be used in an evaluation of market resilience. This is because market resilience is difficult to evaluate on a an ex ante basis when the market has not been subject to a shock.

Where threshold values are provided they are indicative of what would be observed in a liquid market. In other words, the analysis will not be focussed solely on the performance of the metrics relative to the thresholds. The analysis will also take into account the level and rate of change in the chosen metrics and the overall trend in market liquidity. Qualitative information gathered based on the experience and expectations of market participants will also be an important aspect of the analysis.

The metrics in Table F.1 are a starting point and designed to monitor the emergence of liquidity in the wholesale gas market, including in pipeline capacity trading. In the future as the market grows and develops it may be appropriate to include additional metrics in the analysis that are designed to measure liquidity in more mature markets.

F.3.1 Quantitative metrics

Table F.1 shows seven potential metrics which may be used to assess liquidity in the wholesale gas market. Of the seven metrics listed above, the first five are quantitative indicators, that is to say that they can be objectively measured and quantified. Each of the five metrics is discussed in more detail below.

Churn rate

Churn rate is defined as the ratio of all traded volumes to the demand for the underlying physical product, whether that is gas or pipeline capacity. The churn rate is commonly used in commodity and financial markets to assess maturity and liquidity of a given market.

A high churn rate is indicative of a market that has many participants (and many participant types), trading many different products in large volumes. In commodity markets, a churn rate of 10 or more is deemed to signify that the market has reached maturity and is liquid. In analysing European gas markets, ACER recognise that many markets cannot realistically be expected to reach churn rates associated with mature liquid markets.[274] This would also be the expectation with respect to the east coast wholesale gas market in the near to medium term.

Bid-offer spreads

Bid-offer spreads are the difference between the price on the bid side of the market and the price on the offer side of the market. As such, bid-offer spreads include transaction costs, amongst other things. In a liquid market with many well-informed participants, supply and demand should be well aligned and transaction costs to trading gas should be minimised. As a result, a liquid market is characterised by narrow bid-offer spreads.

274 ACER *Implementation monitoring and managing the impact of the gas networks codes and guidelines on the internal market* Final Report, October 2015, pp. 139-141.

While no threshold level for bid-offer spreads has been specified, it would be expected that as the market becomes more liquid the spread between bid and offer prices would become narrower.

Number of participants engaged in trading

Metrics relating to the number of participants that commonly trade are useful to measure the depth and breadth of a market. A large number of market participants engaged in trading mean that it is less likely the market can be manipulated, and therefore the resulting market price will more accurately represent supply and demand conditions.

It should be noted that there are numerous types of participants in the wholesale gas market. For example, a physical participant is one that sells and consumes natural gas and includes producers, shippers, retailers and large users.[275] Financial participants do not have a physical position in gas but may be active in the markets for financial products for hedging or speculative purposes - this means that they close out positions before being required to deliver or take receipt of the gas. A liquid market is generally characterised as one with active physical and financial players.

For the metric listed in Table F.1 it is necessary to define an "active" participant in the market. We propose defining an active participant as one that has been engaged in trading on the market at least once in any given month.

The Stage 2 Draft Report includes a threshold ratio of market participants trading at the hub to physical participants on the east coast. This threshold measures the number of physical players in the east coast gas market and compares them to the number of participants that are actively trading at the hubs. It may be the case that not all physical players will use the hubs initially, as they continue to buy and/or sell gas through contracts, but over time the proportion of physical players to actively trading players will grow. The threshold is therefore designed to measure the level of participation at the hubs and the level for this threshold has been set at the aspirational level of 100 per cent.

Number of trades per product

The number of trades completed for a given product provides a measure of the growth in liquidity on a per product basis at the hubs. A liquid market is characterised by ease of trade and therefore it is expected that the number of trades per product will increase as market liquidity develops. By examining the number of trades on a per product basis the relative development of the market for different products can be distinguished.[276]

275 Physical participants may not necessarily be active in trading markets, for example they may buy or sell all of their gas through bilateral contracts outside of a trading market.

276 An alternative metric to the number of trades for each product is the volume of gas traded per product. However traded volumes may vary widely across products as the size of trades, in energy

While no threshold has been set as to the absolute number of trades per product, the Stage 2 Draft Report specified a price relevance threshold of ≥15 trades per product. The price relevance threshold relates to the number of trades required in order that the price signal for that product can be considered trustworthy. The analysis will compare products against this threshold but will acknowledge that it may take time for such a threshold to be reached and that for some products it may take considerably longer for this threshold value of trades to be realised. As liquidity in the market develops, the number of trades per product is expected to increase. Therefore, the analysis will largely focus on the trend in this series.

Range of products available

In addition to monitoring the number of transactions per product it is necessary to examine the range of products available in the wholesale gas market. A liquid market is one in which participants are able to find a suitable product to satisfy all of their needs and this means that a variety of products should be available. The larger the range of products available, the greater the choice for market participants.

When examining the range of products available on the traded markets, all categories of products should be included; this means that the analysis should include bilateral, OTC and exchange trading. As liquidity grows in the market it is expected that the range of products available will expand. However, it is not expected that the market for products will grow in a uniform fashion; some products may take longer to come to market and, even in mature markets, liquidity for products far along the traded curve may be quite low.

A threshold value for the range of products has not been specified. However, the Stage 2 Draft Report included a "liquidity trading horizon", which was designed to provide an indication as to which products it is possible to trade into the future. This proposes that products with a time horizon of 12 months is an aspirational goal for the medium term.

F.3.2 Qualitative metrics

The use of qualitative information to supplement the quantitative indicators provides a holistic view of market liquidity. Survey-based information allows for valuable information on the non-quantifiable aspects of the development of liquidity to be incorporated into the analysis.

The survey-based information would focus on two areas: market participants' experience of the market to date and their expectations for the future. Therefore, survey-based information would reveal views on how the market has performed in the

terms, will vary significantly. It should be noted that traded volumes will be collected in order to calculate the churn rate. Depending on the granularity of the data collected it may be possible to examine the volume of gas traded per product to supplement the analysis of number of trades per product.

past but, crucially, a forward-looking assessment of how participants see the market developing in the future.

Surveys can provide particular insight into the level of confidence participants have in the market. Confidence is an important factor in achieving the Energy Council's Vision of a liquid wholesale gas market. In order for market participants to be willing to trade they must have trust that the market price reflects underlying supply and demand.

Another element of liquidity that survey-based, qualitative measures can capture is market participants' expectations of the future state of the market. This is especially useful as the market is in the early stages of development as it could capture changes in the behaviour of market participants that have not yet been reflected in the quantitative indicators. The forward looking element of the survey-based information is also important in that it provides an insight in to the potential for further growth in market liquidity.

F.4 Process for monitoring liquidity

The Commission proposes that analysis on growth in gas market liquidity take the form of a report provided to the Energy Council on a biennial basis. The purpose of the report would be to provide ministers with an update on the development of liquidity in the wholesale gas and pipeline capacity trading market and provide details on progress around achievement of the Energy Council's Vision.

Monitoring the growth in trading liquidity should be done at regular intervals so that temporal trends can be monitored and the development of liquidity assessed as market reforms take place. However, given the stage of development of the east coast gas market, and the time required to implement the reform package, the Commission considers that reporting on a more regular basis, such as annually, would not reveal conclusive insights and risk misinterpreting trends.

The Commission expects the liquidity analysis will take the form of objective reporting of the liquidity metrics and commentary on observed trends. Insights gained from engagement with stakeholders, surveys conducted or any other forms of qualitative indicators would be incorporated into the analysis.

Existing publications that provide market commentary may be useful examples to follow. In the energy sector there are regulatory publications that monitor market developments, including analysis of market liquidity in wholesale gas markets. In Britain, Ofgem introduced reforms to improve liquidity in wholesale power markets and have committed to monitoring the effects of these reforms. As a result, it has published an Annual Report on wholesale power market liquidity which includes a discussion of liquidity metrics.[277] In Europe, the Agency for the Cooperation of Energy Regulators (ACER) undertakes monitoring of the markets for electricity and

277 Ofgem, *Wholesale power market liquidity: Annual report 2015*, September 2015. https://www.ofgem.gov.uk/publications-and-updates/wholesale-power-market-liquidity-annual-report-2015

gas. As part of this market monitoring work, indicators of wholesale market liquidity have been developed and are reported on an annual basis.[278]

The Commission proposes that the first report be provided to the Energy Council in July 2018. This would be around one year after AEMO implements Optional Hub Services at the Wallumbilla GSH and will be 24 months after the Moomba GSH is implemented. Some of the information and pipeline capacity trading reforms may also have been implemented and a survey will be able to capture participants' response to these.

F.4.1 Regular publication of quantitative metrics and supporting data

The quantitative metrics outlined in Table F.1 provide objective measures of liquidity in the wholesale gas market. As such we recommend these metrics, and the underlying data, are published on a regular basis through the AER's website.[279] As the AER publishes wholesale gas market statistics on its website, it would be appropriate for the liquidity metrics and the data series underlying the metrics to be included with these statistics.

The AER would access the required data for publication from AEMO. The Commission acknowledges that some initial work by the AER and AEMO may be necessary to identify the required data and to establish a process for collecting and sharing the data that is not already available to the AER. However, we expect that, once such a process is established, the benefits of regularly publishing the metrics and their underlying data would outweigh the costs.

Multiple data series will be used to construct the quantitative metrics. For example, in order to calculate the churn rate two data series are needed, the traded volume and demand for the underlying physical product. The churn rate is then calculated as a ratio of these two data series. It is recommended that, in addition to the liquidity metrics, the underlying data used to calculate the metrics are published by the AER as they in of themselves provide useful information about the market. In the example of the churn rate, this would mean that three data series are made available - the churn rate (the metric itself), the traded volumes data series and the demand for the underlying physical product data series.

The underlying data can also provide context and further information regarding the metrics. To use the churn rate example, the churn rate may be increasing because the traded volumes are increasing, while the demand for the underlying physical product is unchanged. This information regarding what is driving the change in a given metric is not available without examining the data underlying the calculation of the metric.

278 See http://www.acer.europa.eu/Gas/Market_monitoring/Pages/default.aspx for more information.

279 As the information is at a market-level it is not expected that there would be any issues regarding confidentiality.

The data underlying each of the quantitative metrics listed above are given in Table F.2.

Table F.2 Quantitative metrics and underlying data series

Metric	Underlying data
Churn rate	• traded volumes • demand for underlying physical product
Bid-offer spreads	• bid prices • offer prices
Number of active participants	• number of actively trading participants • number of physical participants
Number of trades per product	• number of trades by product category
Range of traded products	• types of bilateral products available • types of OTC products available • types of exchange traded products available

G Auction for contracted but un-nominated capacity

This appendix provides further detail on the potential design of the auction for contracted but un-nominated capacity discussed in Chapter 5. The appendix discusses the market characteristics which inform many of the Commission's design considerations, and provides a more detailed discussion of combinatorial auctions.

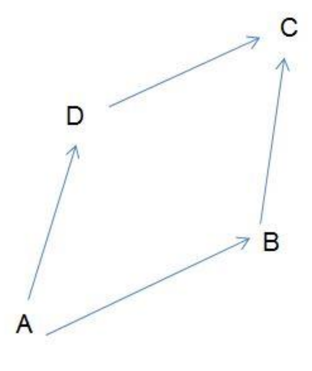
G.1 Market characteristics

The Commission has had regard to the characteristics of the market for contracted but un-nominated capacity, which forms the context for the issues which the auction seeks to address. At a high level, the purpose of the auction is to identify (the combination of) transactions among buyers and sellers in a manner that maximises economic surplus, by allocating capacity to those who value it most at the lowest possible cost. The market characteristics will impose some constraints on how this may be achieved.

The market for pipeline capacity appears to be a **multi-item** market, in that there are different pipelines and segments of pipelines. For example, the South West Queensland Pipeline consists of a 755 km segment from Ballera to Wallumbilla and a 180 km segment from Ballera to Moomba. There are also often **complementarities** (Figure G.1) between items. For instance, a shipper may seek capacity from A to B in order to transport gas from A to C. If the shipper fails to also secure capacity from B to C, then the capacity from A to B lacks value. This means that items either need to be allocated simultaneously, or some other mechanism needs to be used to prevent shippers from becoming stranded with (partial) capacity that cannot be used.

There is also potential for **substitution** between items, as the shippers' needs may be fulfilled using more than one combination of pipeline segments. For example, a shipper seeking to transport gas from A to C can use a route of A to B to C, or A to D to C. Ideally, the auction should allow bidders to express their preferences for multiple combinations of items, some of which may be mutually exclusive. That is, the shipper should be able to place a bid for either of these routes without running the risk of winning both of them.

Figure G.1 Multi-item market with substitutability between items



It appears to be a double-sided **multi-agent** market, with multiple buyers and multiple sellers. A single buyer may need to obtain items from multiple sellers in order to achieve their preferred aggregation. For example, in some circumstances buyers will wish to buy capacity on pipelines owned by two different parties, or may be indifferent to alternative routes owned by different pipeline owners between the same locations. Conversely, a seller may own capacity used by multiple buyers competing for their preferred allocation.

In a competitive market, buyers should have no preferences between sellers, and sellers should have no preferences between buyers, apart from price.

It appears to be **multi-unit** market, as more than one unit may be available of each pipeline segment, and these units may be sold to different bidders.

The items sold have largely **private values** on both the buyer and seller sides. For the buyers, each bidder's valuation of a particular segment of pipeline capacity should be largely independent of its competitors' valuations, as it is derived from its individual commercial contracts and arrangements for selling or using gas. For the sellers, valuations should depend on the individual cost structure of the business.

G.2 Combinatorial auctions

In a combinatorial auction, the allocation mechanism considers multiple products simultaneously, such as capacity on a number of pipeline 'segments' (A to B, and B to C and C to D, and so on). For example, in Figure G.1, a shipper may wish to transport gas from A to C. This could be achieved via the route from A to B to C, or the route from A to D to C. This auction can take into account the substitutability of different packages of items. Participants would be able to place a bid (or set of incremental bids) specifying their preferences over a number of defined dimensions - for example, injection and withdrawal points, and the quantity of capacity required at various prices. The combinatorial algorithm would then translate these preferences into a bid for multiple, mutually exclusive combinations. Using the example in Figure G.1 the algorithm would allocate capacity from A to B **and** B to C, or capacity from A to D **and** D to C.

A combinatorial auction would avoid the 'exposure' problem which arises if pipeline segments are allocated individually. Participants may avoid bidding, or refrain from bidding more than their stand-alone value for each individual item, for fear of not obtaining their preferred aggregation. As per the previous example, a bidder may wish to ship gas from A to C, via B. If, through the auction, it only buys capacity from A to B, and fails to buy capacity from B to C, then the capacity it has bought may be of little worth to it.

Combinatorial auctions have been instituted in a number of settings in Australia and overseas, including the Settlements Residue Auction (SRA) in the NEM[280] and ACMA's digital dividend auctions to allocate radio frequency spectrum.[281]

Box G.1 Settlements Residue Auction

The Settlements Residue Auction (SRA) is an example of a combinatorial auction that exists in the NEM. Inter-regional settlements residue (IRSR) arises in the spot market because there is generally a difference between the amount paid by customers to AEMO for electricity, and the amount paid by AEMO to generators. The difference arises because of power flows between regions where there are different prices – for example between Queensland and New South Wales, or New South Wales and Victoria.

Each quarter, an auction is held to allocate IRSR for all regions and quarters over the next three years. Participants can bid for a portion of IRSR associated with the flow of electricity in a particular direction between two regions. Each bid has four dimensions:

- unit category – the regions and direction of flow the units of IRSR are associated with (for example, New South Wales to Victoria);
- units – the amount the participant is bidding for, expressed as a proportion of accumulated IRSR for the unit category;
- time – the quarter for which the IRSR will be calculated; and
- price – a single price for the bid.

Auction participants can also place 'linked' bids for any combination of unit categories and quarters. A linked category bid will specify demand for units in more than one unit category, while a linked quarter bid will specify demand for units in more than one quarter. By making linked bids, participants can avoid the exposure problem associated with winning some, but not all, of the desired IRSR.

Box G.2 provides a simple example of how the winning combination of bids might be determined by the auction algorithm.

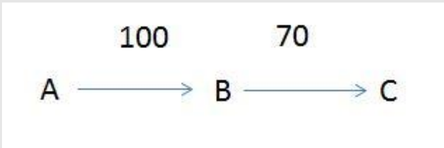
280 See AEMO, *Guide to the Settlements Residue Auction*, July 2014.

281 See http://www.acma.gov.au/Industry/Spectrum/Digital-Dividend-700MHz-and-25Gz-Auction/Reallocation/combinatorial-clock-auctions-reallocation-acma

Box G.2 Determining the winning combination of bids

The following is a simplified worked example of how the combinatorial algorithm might work.

Assume there is a pipeline from A to B to C. There are 100 TJ of capacity available on the A to B segment, and 70 TJ on the B to C segment.



Three shippers, Azealia, Kendrick and Nicki, submit bids for capacity. Each bid has three dimensions:

- **location**, specified in terms of injection and withdrawal points (ie bid for capacity from A to B means an injection point of A and a withdrawal point of B);
- **quantity**, or the number of GJ required; and
- **willingness to pay**, specified as the dollar value the shipper is willing to pay for the total capacity.

Bids are not divisible. That is, if a shipper bids for X units of capacity, either it will be allocated the entire quantity of her bid, or none of it. Each shipper is allowed to submit multiple bids, which they may specify as mutually exclusive (or not). If bids are mutually exclusive, then only one can be part of the winning allocation. Otherwise, the auction will consider allocations which include both (or all) bids submitted by the shipper.

Azealia's, Kendrick's and Nicki's bids are expressed in the table below. Kendrick's bids are mutually exclusive, that is, he wishes to obtain 55 GJ (at a price of $1200) or 30 GJ (at a price of $600) of capacity from A to B, but not both.

Shippers' bids for capacity

Shipper	Location	Quantity demanded (GJ)	Willingness to pay ($)
Azealia	B to C	30	1000
Nicki	A to C	60	2000
Kendrick's first bid	A to B	55	1200
Kendrick's second bid	A to B	30	600

The combinatorial algorithm seeks to maximise profit (revenue minus costs) given constraints. Given a short-run marginal cost of zero, the profit maximising allocation will be equal to the revenue maximising allocation. Constraints arise because the capacity sold on each segment must be less than or equal to the capacity available. In this example:

- allocations from A to B must be less than or equal to 100;
- allocations from B to C must be less than or equal to 70;
- allocations from A to C must be less than or equal to 70;
- the sum of allocations from A to B and A to C must be less than or equal to 100; and
- the sum of allocations from B to C and A to C must be less than or equal to 70.

Feasible combinations of bids

Shipper(s)	Profit ($)
Azealia only	1000
Nicki only	2000
Kendrick's first bid only	1200
Kendrick's second bid only	600
Azealia and Kendrick's first bid	2200
Azealia and Kendrick's second bid	1600
Nicki and Kendrick's second bid	2600

As it turns out, the best combination is to accommodate Nicki's bid and Kendrick's second bid. Kendrick's demand for 30 GJ of capacity from A to B for $600 can be satisfied at the same time as Nicki's demand for 60 GJ of capacity from A to C for $2000, leading to a total profit of $2600.

Some combinations (for example, either of Kendrick's bids and Azealia's bid) are feasible, but do not maximise profit. Other combinations (for example, Kendrick's first bid and Nicki's bid) are not feasible.

While in this example, the winning combination also maximises the throughput of the pipeline, this is not directly relevant to the outcome of the auction: profit maximisation, not volume maximisation, is the objective.